THIS FILING IS		
Item 1: [X] An Initial (Original) Submission	OR [ ]	Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2014)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2014)
Form 3-Q Approved
OMB No.1902-0205
(Expires 05/31/2014)

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

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

Exact Legal Name of Respondent (Company)	Year/Period of Report
Avista Corporation	End of 2013/Q4

FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION	
01 Exact Legal Name of Respondent Avista Corporation	02 Year/Period of Report End of 2013/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 1411 East Mission Avenue, Spokane, WA 99207	
05 Name of Contact Person Christy Burmeister-Smith	06 Title of Contact Person VP, Controller, Prin. Acctg
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*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(509) 495-4256	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Christy Burmeister-Smith	Christy Burmeister-Smith	04/11/2014
02 Title VP, Controller, Prin. Acctg Officer		

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

LIST OF SCHEDULES (Electric Utility)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	N/A
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	N/A
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	N/A
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	N/A
24	Extraordinary Property Losses	230	N/A
25	Unrecovered Plant and Regulatory Study Costs	230	N/A
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

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LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	Footnote Data	450	

Stockholders' Reports Check appropriate box:

[X] Two copies will be submitted

[ ] No annual report to stockholders is prepared

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/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.

C. Burmeister-Smith, Vice President, Controller, and Principal Accounting Officer
1411 E. Mission Avenue
Spokane, WA 99207

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

State of Washington, Incorporated March 15, 1889

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.

Not Applicable

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 Wasington, 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...Enter the date when such independent accountant was initially engaged:
(2) [X] No

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Avista Capital, Inc.	Parent company to the	100	
2		Company's subsidiaries.		
3				
4	Ecova, Inc.	Provider of utility bill	80.2	Subsidiary of
5		processing, payment and		Avista Capital
6		information services to multi		
7		site customers in North Amer.		
8				
9				
10	Avista Development, Inc.	Maintains an investment	100	Subsidiary of
11		portfolio of real estate and		Avista Capital
12		other investments.		
13				
14	Avista Energy, Inc.	Inactive	100	Subsidiary of
15				Avista Capital
16				
17	Pentzer Corporation	Parent company of Bay Area	100	Subsidiary of
18		Manufacturing and Pentzer		Avista Capital
19		Venture Holdings.		
20				
21	Pentzer Venture Holdings	Inactive	100	Subsidiary of
22				Pentzer Corporation
23				
24	Bay Area Manufacturing	Holding Company	100	Subsidiary of
25				Pentzer Corporation
26				
27	Advanced Manufacturing and Development, Inc.	Performs custom sheet metal	82.95	Subsidiary of

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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	dba Metalfx	manufacturing of electronic		Bay Area
2		enclosures, parts and systems		Manufacturing.
3		for the computer, telecom and		
4		medical industries. AM&D		
5		also has a wood products		
6		division.		
7				
8	Spokane Energy, LLC	Owns an electric capactiy	100	Affiliate of
9		contract.		Avista Corp.
10				
11	Avista Capital II	An affiliated business trust	100	Affliate of
12		formed by the Company.		Avista Corp.
13		Issued Pref. Trust Securities		
14				
15	Avista Northwest Resources, LLC	Formed in 2009 to own	100	Affiliate of
16		an interest in a venture		Avista Capital
17		fund investment		
18				
19	Steam Plant Square, LLC	Commercial office and retail	85	Affiliate of
20		leasing.		Avista Development
21				
22	Courtyard Office Center, LLC	Commercial office and retail	100	Affiliate of
23		leasing.		Avista Development
24				
25	Steam Plant Brew Pub, LLC	Restaurant operations	85	Affiliate of Steam
26				Plant Square, LLC
27				

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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Alaska Merger Sub, Inc.	Merger company formed to	100	Subsidiary of
2		effect the merger transaction		Avista Corp.
3		with Alaska Energy and		
4		Resources Company		
5				
6	Salix, Inc.	Liquified natural gas	100	Subsidiary of
7		operations		Avista Capital
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	Chairman of the Board, President	S. L. Morris	
2	and Chief Executive Officer		
3			
4	Senior Vice President, Chief Financial Officer,	M. T. Thies	
5	and Treasurer (effective 1/2013)		
6			
7	Senior Vice President, General Counsel	M. M. Durkin	
8	and Chief Compliance Officer		
9			
10	Senior Vice President and Corporate Secretary	K. S. Feltes	
11	responsible for Human Resources		
12			
13	Senior Vice President and Environmental	D. P. Vermillion	
14	Compliance Officer, President of Avista Utilities		
15			
16	Vice President, Controller, and	C. M. Burmeister-Smith	
17	Principal Accounting Officer		
18			
19	Vice President, Chief Information Officer, and	J. M. Kensok	
20	Chief Security Officer (effective 5/2013)		
21			
22	Vice President, responsible for Energy Delivery	D. F. Kopczynski	
23	and Customer Service		
24			
25	Vice President and Chief Counsel for Regulatory	D. J. Meyer	
26	and Governmental Affairs		
27			
28	Vice President, responsible for State and Federal	K. O. Norwood	
29	Regulations		
30			
31	Vice President and Chief Strategy Officer	R. D. Woodworth	
32			
33	Vice President, responsible for Energy Resources	J. R. Thackston	
34	(effective 1/2013)		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Scott L. Morris**	1411 E Mission Ave., Spokane, WA, 99202
2	(Chairman of the Board, President & CEO)	
3		
4	Erik J. Anderson	3720 Carillon Point, Kirkland, WA 98033
5		
6	Kristianne Blake***	P.O. Box 28338, Spokane, WA 99228
7		
8	Donald C. Burke	16 Ivy Court, Langhorne, PA 19047
9		
10	Rick R. Holley	999 Third Ave., Suite 4300, Seattle, WA 98104
11		
12	John F. Kelly***	851 Georgia Ave., Winter Park, FL 33143
13		
14	Michael L. Noel (retired from Board 5/2013)	11960 W. Six Shooter Rd., Prescott, AZ 86305
15		
16	Heidi B. Stanley	P.O. Box 2884, Spokane, WA 99220
17		
18	R. John Taylor***	111 Main Street, Lewiston, ID 83501
19		
20	Marc F. Racicot	28013 Swan Cove Dr., Big Fork, MT 59911
21		
22	Rebecca A. Klein	611 S. Congress Ave., Suite 125, Austin, TX 78704
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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates?

[ ] Yes
[X] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
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INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)?

[ ] Yes
[X] No

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

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
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INFORMATION ON FORMULA RATES
Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s).	Schedule	Column	Line No
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IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

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

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

1. None
2. A merger transaction with Alaska Energy and Resources Company was entered into on November 4, 2013; however, the consummation of the transaction is subject to the satisfaction or waiver of specified closing conditions. Refer to Note 3 of the Notes to Financial Statements for further details regarding this merger transaction.
3. None
4. None
5. None
6. Avista Corp. has a committed line of credit with various financial institutions in the total amount of $400.0 million with an expiration date of February 2017. The committed line of credit is secured by non-transferable First Mortgage Bonds of the Company issued to the agent bank that would only become due and payable in the event, and then only to the extent, that the Company defaults on its obligations under the committed line of credit.

Balances outstanding under the Company's revolving committed line of credit were as follows as of December 31, 2013 and December 31, 2012 (dollars in thousands):

	December 31, 2013	December 31, 2012
Balance outstanding at end of period	$171,000	$52,000
Letters of credit outstanding at end of period	$27,434	$35,885

In August 2013, Avista Corp. entered into a $90.0 million term loan agreement with an institutional investor that bears an annual interest rate of 0.84 percent and matures in 2016. The term loan agreement is secured by non-transferable First Mortgage Bonds of the Company issued to the agent bank that will only become due and payable in the event, and then only to the extent, that the Company defaults on its obligations under the term loan agreement. The net proceeds from the $90.0 million term loan agreement were used to repay a portion of corporate indebtedness in anticipation of $50.0 million in First Mortgage Bonds that matured in December 2013. The debt issuance was approved by regulatory commissions as follows:WUTC (Docket No. U-111176 Order 02) IPUC (Case No. AVU-U-11-01 Order No. 32338) and the OPUC (Docket UF 4269 Order No. 11-334).

7. None
8. Average annual wage increases were 2.2% for non-exempt employees effective February 25, 2013. Average annual wage increases were 2.8% for exempt employees effective February 25, 2013. Officers received average increases of 5.5% effective February 25, 2013. Certain bargaining unit employees received increases of 3.0% effective March 26, 2013.
9. Reference is made to Note 17 of the Notes to Financial Statements.
10. None
11. Reserved
12. See page 123 of this report.
13. Michael L. Noël, a director of Avista Corporation (Avista Corp. or the Company) whose term expired on May 9, 2013, retired from Avista Corp.'s Board of Directors as he has reached the mandatory retirement age of 72 as outlined in the Company's Bylaws.

On February 11, 2014, Rick R. Holley provided notification to the Company that he will not stand for reelection to Avista Corp.'s Board of Directors and he resigned effective February 15, 2014. This is due to the fact that the time requirements for his board service conflicts with his other professional commitments. He has no disagreements with the Company.

On February 13, 2014, Avista Corp.'s Board of Directors took action to reduce the number of board members from 10 to 9 effective February 15, 2014.

Effective January 2014, Jason R. Thackston was promoted to Senior Vice President. He has been Vice President of Energy Resources since December 2012.

14. Proprietary capital is not less than 30 percent.

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2014	Year/Period of Report End of 2013/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	4,280,005,611	4,044,184,930
3	Construction Work in Progress (107)	200-201	157,258,690	139,513,892
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		4,437,264,301	4,183,698,822
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	1,491,212,830	1,408,153,972
6	Net Utility Plant (Enter Total of line 4 less 5)		2,946,051,471	2,775,544,850
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		2,946,051,471	2,775,544,850
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		6,992,076	6,992,076
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		5,438,891	5,536,702
19	(Less) Accum. Prov. for Depr. and Amort. (122)		920,905	921,820
20	Investments in Associated Companies (123)		12,047,000	12,047,000
21	Investment in Subsidiary Companies (123.1)	224-225	112,232,104	118,714,423
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		13,980,638	16,439,055
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		10,897,909	9,154,874
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		853,757	1,092,593
31	Long-Term Portion of Derivative Assets – Hedges (176)		19,574,858	7,265,426
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		174,104,252	169,328,253
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		3,949,469	2,624,516
36	Special Deposits (132-134)		19,283,082	2,716,333
37	Working Fund (135)		864,092	799,065
38	Temporary Cash Investments (136)		0	251,390
39	Notes Receivable (141)		0	234,901
40	Customer Accounts Receivable (142)		182,617,384	159,703,153
41	Other Accounts Receivable (143)		8,417,179	5,188,679
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		4,830,036	4,653,167
43	Notes Receivable from Associated Companies (145)		5,720,836	314,682
44	Accounts Receivable from Assoc. Companies (146)		286,696	700,835
45	Fuel Stock (151)	227	3,170,050	4,120,767
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	26,655,710	23,875,397
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		13,028,710	17,276,287
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		7,938,050	16,090,480
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		30,982	31,981
60	Rents Receivable (172)		1,360,262	830,718
61	Accrued Utility Revenues (173)		0	0
62	Miscellaneous Current and Accrued Assets (174)		752,953	429,169
63	Derivative Instrument Assets (175)		3,875,269	5,231,375
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		853,757	1,092,593
65	Derivative Instrument Assets - Hedges (176)		33,544,588	7,265,426
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		19,574,858	7,265,426
67	Total Current and Accrued Assets (Lines 34 through 66)		286,236,661	234,673,968
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		12,505,134	13,532,890
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	381,581,939	559,831,454
73	Prelim. Survey and Investigation Charges (Electric) (183)		875,153	3,894,551
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		0	0
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	13,312,292	15,701,369
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		19,417,103	21,635,414
82	Accumulated Deferred Income Taxes (190)	234	70,239,422	148,425,469
83	Unrecovered Purchased Gas Costs (191)		-12,074,780	-6,916,577
84	Total Deferred Debits (lines 69 through 83)		485,856,263	756,104,570
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		3,899,240,723	3,942,643,717

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	end of 2013/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	869,342,827	863,316,222
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	0
7	Other Paid-In Capital (208-211)	253	8,089,025	10,942,942
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	-19,561,527	-14,977,565
11	Retained Earnings (215, 215.1, 216)	118-119	413,009,873	377,687,824
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-5,918,024	-747,337
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-5,819,930	-6,700,160
16	Total Proprietary Capital (lines 2 through 15)		1,298,265,298	1,259,477,056
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,376,700,000	1,336,700,000
19	(Less) Reaquired Bonds (222)	256-257	83,700,000	83,700,000
20	Advances from Associated Companies (223)	256-257	51,547,000	51,547,000
21	Other Long-Term Debt (224)	256-257	0	0
22	Unamortized Premium on Long-Term Debt (225)		195,433	204,316
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		1,482,644	1,656,685
24	Total Long-Term Debt (lines 18 through 23)		1,343,259,789	1,303,094,631
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		4,193,852	4,491,191
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		240,000	700,447
29	Accumulated Provision for Pensions and Benefits (228.3)		122,512,892	283,984,764
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		2,489,686	0
32	Long-Term Portion of Derivative Instrument Liabilities		18,355,040	26,310,290
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		2,847,207	3,167,936
35	Total Other Noncurrent Liabilities (lines 26 through 34)		150,638,677	318,654,628
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		171,000,000	52,000,000
38	Accounts Payable (232)		107,675,819	116,147,642
39	Notes Payable to Associated Companies (233)		0	598
40	Accounts Payable to Associated Companies (234)		810,911	709,623
41	Customer Deposits (235)		3,393,269	3,323,152
42	Taxes Accrued (236)	262-263	22,103,801	22,309,642
43	Interest Accrued (237)		13,444,066	12,038,698
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	end of 2013/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		115,213	120,427
48	Miscellaneous Current and Accrued Liabilities (242)		55,243,462	61,331,657
49	Obligations Under Capital Leases-Current (243)		297,339	258,586
50	Derivative Instrument Liabilities (244)		29,230,059	55,825,491
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		18,355,041	26,310,290
52	Derivative Instrument Liabilities - Hedges (245)		0	1,433,160
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		384,958,898	299,188,386
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		1,459,117	947,342
57	Accumulated Deferred Investment Tax Credits (255)	266-267	12,387,031	12,613,058
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	25,359,333	26,169,966
60	Other Regulatory Liabilities (254)	278	71,742,330	55,244,962
61	Unamortized Gain on Reaquired Debt (257)		2,225,581	2,355,118
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		447,100,235	419,216,613
64	Accum. Deferred Income Taxes-Other (283)		161,844,434	245,681,957
65	Total Deferred Credits (lines 56 through 64)		722,118,061	762,229,016
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		3,899,240,723	3,942,643,717

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

STATEMENT OF INCOME

Quarterly

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

Annual or Quarterly if applicable

5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	1,574,987,368	1,494,227,540		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,054,508,447	1,051,630,004		
5	Maintenance Expenses (402)	320-323	60,947,443	61,377,568		
6	Depreciation Expense (403)	336-337	105,822,752	102,188,312		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	13,800,853	12,353,382		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	99,047	99,047		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		12,986,972	5,612,331		
13	(Less) Regulatory Credits (407.4)		13,582,146	24,170,474		
14	Taxes Other Than Income Taxes (408.1)	262-263	88,262,771	83,263,801		
15	Income Taxes - Federal (409.1)	262-263	39,972,039	14,435,558		
16	- Other (409.1)	262-263	2,066,338	379,911		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	31,154,269	35,782,466		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	4,770,686	4,224,555		
19	Investment Tax Credit Adj. - Net (411.4)	266	-238,869	2,073,106		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,391,029,230	1,340,800,457		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		183,958,138	153,427,083		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
1,049,456,902	1,017,916,105	525,530,466	476,311,435			2
						3
635,615,026	664,363,922	418,893,421	387,266,082			4
48,867,669	50,481,432	12,079,774	10,896,136			5
84,631,445	83,017,204	21,191,307	19,171,108			6
						7
10,778,960	9,725,903	3,021,893	2,627,479			8
99,047	99,047					9
						10
						11
12,125,143	4,618,160	861,829	994,171			12
13,080,536	22,537,730	501,610	1,632,744			13
66,342,004	62,217,029	21,920,767	21,046,772			14
31,663,448	16,824,429	8,308,591	-2,388,871			15
1,388,109	432,992	678,229	-53,081			16
25,700,222	24,012,637	5,454,047	11,769,829			17
4,871,648	4,120,508	-100,962	104,047			18
-199,113	2,115,166	-39,756	-42,060			19
						20
						21
						22
						23
						24
899,059,776	891,249,683	491,969,454	449,550,774			25
150,397,126	126,666,422	33,561,012	26,760,661			26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		183,958,138	153,427,083		
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 Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)		-13,172	-236		
34	(Less) Expenses of Nonutility Operations (417.1)		10,644,789	8,415,859		
35	Nonoperating Rental Income (418)		-3,699	-2,749		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	4,593,239	-1,206,861		
37	Interest and Dividend Income (419)		2,432,397	1,864,293		
38	Allowance for Other Funds Used During Construction (419.1)		6,065,628	4,054,947		
39	Miscellaneous Nonoperating Income (421)					
40	Gain on Disposition of Property (421.1)					
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		2,429,604	-3,706,465		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		3,320,437	2,272,123		
46	Life Insurance (426.2)		2,599,896	2,533,552		
47	Penalties (426.3)		109,224	15,251		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,605,677	1,414,338		
49	Other Deductions (426.5)		4,366,477	1,815,326		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		12,001,711	8,050,590		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	172,447	145,213		
53	Income Taxes-Federal (409.2)	262-263	-481,927	106,965		
54	Income Taxes-Other (409.2)	262-263	-1,004,519	-1,231,456		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	-1,731,439	-520,718		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	5,632,031	5,190,742		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-8,677,469	-6,690,738		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-894,638	-5,066,317		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		68,485,495	65,281,624		
63	Amort. of Debt Disc. and Expense (428)		448,328	447,351		
64	Amortization of Loss on Reaquired Debt (428.1)		3,373,538	3,364,150		
65	(Less) Amort. of Premium on Debt-Credit (429)		8,883	8,883		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		750,512	885,123		
68	Other Interest Expense (431)		2,613,463	2,582,407		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		3,675,786	2,401,072		
70	Net Interest Charges (Total of lines 62 thru 69)		71,986,667	70,150,700		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		111,076,833	78,210,066		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		111,076,833	78,210,066		

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		376,139,703	362,988,164
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		98,317,714	79,416,927
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31			-73,276,102	(68,552,375)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-73,276,102	(68,552,375)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		2,114,557	2,286,987
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		403,295,872	376,139,703
	APPROPRIATED RETAINED EARNINGS (Account 215)			

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STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

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)
39			9,714,001	1,548,121
40				
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)		9,714,001	1,548,121
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		9,714,001	1,548,121
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		413,009,873	377,687,824
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-747,337	(28,386,302)
50	Equity in Earnings for Year (Credit) (Account 418.1)		4,593,239	(1,206,861)
51	(Less) Dividends Received (Debit)			
52	Equity Transactions of subsidiaries		-9,763,926	28,845,826
53	Balance-End of Year (Total lines 49 thru 52)		-5,918,024	(747,337)

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The balance transferred from income to unapprorpriated retained earnings does not equal net income less subsidiary earnings in the current year because a portion of net income for the current year was recorded to 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 hydro projects. The rate of return on investment is specified in the various hydroelectric licensing agreements for the Clark Fork River and Spokane River. 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.

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	111,076,833	78,210,066
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	117,173,574	112,091,663
5	Amortization of deferred power and natural gas costs	-9,407,533	6,702,266
6	Amortization of debt expense	3,812,982	3,802,618
7	Amortization of investment in exchange power	2,450,031	2,450,031
8	Deferred Income Taxes (Net)	20,846,650	19,589,845
9	Investment Tax Credit Adjustment (Net)	-226,027	2,212,172
10	Net (Increase) Decrease in Receivables	-30,523,370	12,838,942
11	Net (Increase) Decrease in Inventory	2,417,981	4,331,613
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-4,903,140	31,767,362
14	Net (Increase) Decrease in Other Regulatory Assets	-899,982	-4,674,400
15	Net Increase (Decrease) in Other Regulatory Liabilities	7,774,282	-4,241,041
16	(Less) Allowance for Other Funds Used During Construction	6,065,628	4,054,947
17	(Less) Undistributed Earnings from Subsidiary Companies	4,593,239	-1,206,861
18	Other (provide details in footnote):	-4,736,292	17,162,806
19	Allowance for doubtful accounts	4,792,409	3,973,772
20	Changes in other non-current assets and liabilities	-7,470,522	-7,388,676
21	Write-off of Reardan wind generation assets	2,533,578	
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	204,052,587	275,980,953
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-294,363,192	-268,743,138
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction		
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-294,363,192	-268,743,138
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38	Federal grant payments received	3,409,479	8,277,036
39	Investments in and Advances to Assoc. and Subsidiary Companies	-4,891,325	-19,138,510
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48	Restricted Cash	481,170	
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
54	Changes in other property and investments	6,167	4,540,198
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-295,357,701	-275,064,414
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	90,000,000	80,000,000
62	Preferred Stock		
63	Common Stock	4,609,006	29,078,745
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	94,609,006	109,078,745
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-50,258,586	-11,324,884
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Debt issuance costs	-531,294	-763,603
78	Net Decrease in Short-Term Debt (c)	119,000,000	-9,000,000
79	Cash received (paid) for settlement of interest rate swap	2,900,680	-18,546,870
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-73,276,102	-68,552,375
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	92,443,704	891,013
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	1,138,590	1,807,552
87			
88	Cash and Cash Equivalents at Beginning of Period	3,674,971	1,867,419
89			
90	Cash and Cash Equivalents at End of period	4,813,561	3,674,971

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Power and natural gas deferrals	1,284,946
Change in special deposits	(16,072,800)
Change in other current assets	7,300,101
Non-cash stock compensation	5,036,659
Cash paid for foreign currency hedges	(30,270)
Change in Coyote Springs 2 O&M LTSA	(1,376,514)
Preliminary survey and investigation costs	(878,414)

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Power and natural gas deferrals	1,704,991
Change in special deposits	9,792,264
Change in other current assets	1,080,222
Non-cash stock compensation	4,549,448
Cash received for foreign currency hedges	35,881

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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

NOTES TO FINANCIAL STATEMENTS

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

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SEE PAGE 123 FOR REQUIRED INFORMATION.

NOTES TO FINANCIAL STATEMENTS

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Business

Avista Corporation (Avista Corp. or the Company) is an energy company engaged in the generation, transmission and distribution of electricity and the distribution of natural gas, as well as other energy-related businesses. Avista Corp. provides electric distribution and transmission, as well as 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 generating facilities in Washington, Idaho, Oregon and Montana. The Company also supplies electricity to a small number of customers in Montana, most of whom are employees who operate one of the Montana generating facilities. Avista Capital, Inc. (Avista Capital), a wholly owned subsidiary of Avista Corp., is the parent company of all of the subsidiary companies, except Spokane Energy, LLC (Spokane Energy). Avista Capital's subsidiaries include Ecova, Inc. (Ecova), a 80.2 percent owned subsidiary as of December 31, 2013. Ecova is a provider of energy efficiency and other facility information and cost management programs and services for multi-site customers and utilities throughout North America.

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 System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America (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 and (6) comprehensive income.

Use of Estimates

The preparation of the financial statements in conformity with accounting principles generally accepted in the United States of America (U.S. GAAP) requires management to make estimates and assumptions that affect amounts reported in the financial statements. Significant estimates include:

- determining the market value of energy commodity derivative assets and liabilities,
- pension and other postretirement benefit plan obligations,
- contingent liabilities,
- 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 Federal Energy Regulatory Commission (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 and Oregon. 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.

Operating Revenues

Revenues related to the sale of energy are recorded when service is rendered or energy is delivered to customers. The determination of the energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. 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.

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

	2013	2012
Unbilled accounts receivable	$ 81,059	$ 77,298

Advertising Expenses

The Company expenses advertising costs as incurred. Advertising expenses were not a material portion of the Company's operating expenses in 2013 and 2012.

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:

	2013	2012
Ratio of depreciation to average depreciable property	2.90%	2.92%

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

- electric thermal production - 41 years,
- hydroelectric production - 79 years,
- electric transmission - 56 years,
- electric distribution - 36 years, and
- natural gas distribution property - 48 years.

Taxes Other Than Income Taxes

Taxes other than income taxes include state excise taxes, city occupational and franchise taxes, real and personal property taxes and certain other taxes not based on net income. These taxes are generally based on revenues or the value of property. Utility related taxes collected from customers (primarily state excise taxes and city utility taxes) are recorded as operating revenue and expense and totaled the following amounts for the years ended December 31 (dollars in thousands):

	2013	2012
Utility taxes	$ 55,565	$ 53,716

Allowance for Funds Used During Construction

The 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 and the debt related portion is credited against total interest expense in the Statements of Income. 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 effective AFUDC rate was the following for the years ended December 31:

	2013	2012
Effective AFUDC rate	7.64%	7.62%

Income Taxes

A deferred income tax asset or liability is determined based on the enacted tax rates that will be in effect when the 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 deferred income tax expense for the period is equal to the net change in the deferred income tax asset and liability accounts from the beginning to the end of the period. The effect on deferred income taxes from a change in tax rates is recognized in income in the period that includes the enactment date. Deferred income tax liabilities and regulatory assets are established for income tax benefits flowed through to customers as prescribed by the respective regulatory commissions.

Stock-Based Compensation

Compensation cost relating to share-based payment transactions is recognized in the Company's financial statements based on the fair value of the equity or liability instruments issued and recorded over the requisite service period. See Note 16 for further information.

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 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.

Derivative Assets and Liabilities

Derivatives are recorded as either assets or liabilities on the Balance Sheets measured at estimated fair value. In certain defined conditions, a derivative may be specifically designated as a hedge for a particular exposure. The accounting for derivatives depends on the intended use of the derivatives and the resulting designation.

The Washington Utilities and Transportation Commission (UTC) and the Idaho Public Utilities Commission (IPUC) issued accounting orders authorizing Avista Corp. to offset 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. The orders provide for Avista Corp. to not recognize the unrealized gain or loss on utility derivative commodity instruments in the Statements of Income. Realized gains or losses are recognized in the period of delivery, subject to approval for recovery through retail rates. Realized gains and losses, subject to regulatory approval, result in adjustments to retail rates through purchased gas cost adjustments, the Energy Recovery Mechanism (ERM) in Washington, the Power Cost Adjustment (PCA) mechanism in Idaho, and periodic general rates cases. Regulatory assets are assessed regularly and are probable for 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.

Fair Value Measurements

Fair value represents the price that would be received to sell 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 agreements and foreign currency exchange contracts, are reported at estimated fair value on the Balance Sheets. See Note 14 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 included 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. 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 not recovered through rates at the time such costs are incurred, even if the Company expected to recover such costs in the future.

See Note 19 for further details of regulatory assets and liabilities.

Investment in Exchange Power-Net

The investment in exchange power represents the Company's previous investment in Washington Public Power Supply System Project 3 (WNP-3), a nuclear project that was terminated prior to completion. Under a settlement agreement with the Bonneville Power Administration in 1985, Avista Corp. began receiving power in 1987, for a 32.5-year period, related to its investment in WNP-3. Through a settlement agreement with the UTC in the Washington jurisdiction, Avista Corp. is amortizing the recoverable portion of its investment in WNP-3 (recorded as investment in exchange power) over a 32.5-year period that began in 1987. For the Idaho jurisdiction, Avista Corp. fully amortized the recoverable portion of its investment in exchange power.

Unamortized Debt Expense

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

Unamortized Loss on Reacquired Debt

For the Company's Washington regulatory jurisdiction and for any debt repurchases beginning in 2007 in all jurisdictions, premiums 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 costs are amortized over the life of the new debt. In the Company's other regulatory jurisdictions, premiums 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. 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 hydro projects. The rate of return on investment is specified in the various hydroelectric licensing agreements for the Clark Fork River and Spokane River. 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 appropriated retained earnings amounts included in retained earnings were as follows as of December 31 (dollars in thousands):

	2013	2012
Appropriated retained earnings	$ 9,714	$ 1,548

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 losses that do not meet these conditions for accrual, if there is a reasonable possibility that a loss may be incurred.

Voluntary Severance Incentive Program

At December 31, 2012, the Company accrued total severance costs of $7.3 million (pre-tax) related to the voluntary termination of 55 employees. The total severance costs were made up of the severance payments and the related payroll taxes and employee benefit costs. All terminations under the voluntary severance incentive program were completed by December 31, 2012. The cost of the program was recognized as expense during the fourth quarter of 2012 and severance pay was distributed in a single lump sum cash payment to each participant during January 2013. As of December 31, 2013, there was no remaining liability accrued.

NOTE 2. NEW ACCOUNTING STANDARDS

In February 2013, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2013-02, "Comprehensive Income (Topic 220): Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income." This ASU does not change current requirements for reporting net income or other comprehensive income in financial statements; however, it requires entities to disclose the effect on the line items of net income for reclassifications out of accumulated other comprehensive income if the item being reclassified is required to be reclassified in its entirety to net income under U.S. GAAP. For other items that are not required to be reclassified in their entirety to net income under U.S. GAAP, an entity is required to cross-reference other disclosures required under U.S. GAAP to provide additional detail about those items. The Company adopted this ASU effective January 1, 2013. The adoption of this ASU required additional disclosures in the Company's financial statements; however, it did not have any impact on the Company's financial condition, results of operations and cash flows.

In December 2011, the FASB issued ASU No. 2011-11, "Balance Sheet (Topic 210): Disclosures about Offsetting Assets and Liabilities." This ASU enhances disclosure requirements about the nature of an entity's right to offset and related arrangements associated with its financial instruments and derivative instruments. ASU No. 2011-11 requires the disclosure of the gross amounts subject to rights of set off, amounts offset in accordance with the accounting standards followed, and the related net exposure. The Company adopted this ASU effective January 1, 2013. The adoption of this ASU required additional disclosures in the Company's financial statements; however, it did not have any impact on the Company's financial condition, results of operations and cash flows.

In January 2013, the FASB issued ASU No. 2013-01, "Balance Sheet (Topic 210): Clarifying the Scope of Disclosures about Offsetting Assets and Liabilities." This ASU clarifies which instruments and transactions are subject to the enhanced disclosure requirements of ASU 2011-11 regarding the offsetting of financial assets and liabilities. ASU No. 2013-01 limits the scope of ASU No. 2011-11 to only recognized derivative instruments, repurchase agreements and reverse repurchase agreements, and borrowing and lending securities transactions that are offset in accordance with either Accounting Standards Codification (ASC) 210-20-45 or ASC 815-10-45. The Company adopted this ASU effective January 1, 2013. The adoption of this ASU did not have any impact on the Company's financial condition, results of operations and cash flows.

On February 20, 2014, the Federal Energy Regulatory Commission (FERC) issued a Final Rule with a retroactive effective date of January 1, 2013, which revised certain aspects of its accounting and reporting requirements under its Uniform System of Accounts for public utilities. The accounting and reporting revisions in the Final Rule adopted new, and revised existing, electric plant accounts and associated Operation and Maintenance expense accounts, including a purchased power account, to separately identify equipment and costs related to new electric storage technologies. In addition, FERC adopted new schedules in the Form Nos. 1 and 1-F and revised existing schedules in the FERC Forms to separately identify the electric storage activities. The Final Rule also included additional footnote disclosure requirements. The Company evaluated the FERC's Final Rule and concluded that within its regulated operations which are subject to FERC reporting requirements, the Company is not performing any activities associated with electric storage and the Final Rule has no impact on the Company for 2013. The Company will continue to evaluate the Final Rule on an annual basis to determine whether it becomes applicable.

NOTE 3. BUSINESS ACQUISITIONS

Alaska Energy and Resources Company - Avista Corporation

On November 4, 2013, the Company entered into an agreement and plan of merger (Merger Agreement) with AERC, a privately-held company based in Juneau, Alaska. When the transaction is completed, AERC will become a wholly-owned subsidiary of Avista Corp.

The primary subsidiary of AERC is AEL&P, the sole provider of electric services to approximately 16,000 customers in the City and Borough of Juneau, Alaska. In 2012, AEL&P had annual revenues of $42 million, a total rate base of $111 million and had 60 full-time employees. The utility has a firm retail peak load of approximately 80 MW. AEL&P owns four hydroelectric generating facilities, having a total present capacity of 24.7 MW, and has a power purchase commitment for the output of the Snettisham hydroelectric project, having a present capacity of 78 MW, for a total hydroelectric capacity of 102.7 MW. AEL&P is not interconnected to any other electric system; therefore, the utility has 93.9 MW of diesel generating present capacity to provide back-up service to firm customers when necessary.

In addition to the regulated utility, AERC owns the AJT Mining subsidiary, which is an inactive mining company holding certain mining properties.

The merger consideration at closing will be $170 million, less AERC's indebtedness and is subject to other customary closing adjustments (Merger Consideration). The transaction will be funded primarily through the issuance of Avista Corp. common stock to the shareholders of AERC. The transaction is expected to close by July 1, 2014, following the receipt of necessary regulatory approvals, the approval of the merger transaction by the requisite number of AERC shareholders and the satisfaction of other closing conditions. Avista Corp. shareholder approval is not required.

Pursuant to the Merger Agreement, among other things, each of the issued and outstanding shares of AERC common stock (other than Dissenting Shares) will be converted into the right to receive consideration as follows:

i. the number of shares of Avista Corp. common stock equal to one share of AERC common stock multiplied by the Exchange Ratio; and

ii. a portion of the Representative Reimbursement Amount.

For purposes of the foregoing:

The ***Exchange Ratio*** is the ratio obtained by dividing the Per Share Amount by (i) $21.48 if the Avista Corp. Closing Price is less than or equal to $21.48, (ii) the Avista Corp. Closing Price, if the Avista Corp. Closing Price is greater than $21.48 and less than $34.30 or (iii) $34.30 if the Avista Corp. Closing Price is greater than or equal to $34.30.

The ***Per Share Amount*** is the amount determined by *dividing* (a) the Merger Consideration (as adjusted) *by* (b) the aggregate number of shares of AERC common stock outstanding immediately prior to the closing of the transaction.

The ***Representative Reimbursement Amount*** is a $500,000 cash payment to be made by Avista Corp. at the Closing to the Shareholders' Representative account. The purpose of the Representative Reimbursement Amount is to reimburse the Shareholders' Representative for expenses incurred by the Shareholders' Representative in acting for the current shareholders of AERC in connection with the Merger. The total Merger Consideration will be reduced by the Representative Reimbursement Amount.

Dissenting Shares will not be converted into, or represent the right to receive, the Merger Consideration or any portion of the Representative Reimbursement Amount. Such shareholders will be entitled to receive payment of the fair value of Dissenting Shares held by them in accordance with the provisions of AS 10.06.580 of the Alaska Corporations Code. Any amounts paid to Dissenting Shares over the amounts otherwise payable in the form of Merger Consideration are indemnified expenses owed by AERC to Avista Corp.

The Merger Agreement has been approved by Avista Corp.'s and AERC's Boards of Directors, the UTC, the U.S. Federal Trade Commission and the Antitrust Division of the U.S. Department of Justice, but the consummation of the transaction is subject to the satisfaction or waiver of specified closing conditions, including:

- the registration under the Securities Act of 1933 of the shares of common stock that will be issued to AERC shareholders;
- the approval of such shares for listing on the New York Stock Exchange;
- the approval of the merger transaction by the requisite number of AERC shareholders;
- the receipt of regulatory approvals and other consents required to consummate the merger transaction, including, among others, approvals from the RCA, the IPUC, the OPUC and any other applicable regulatory bodies on the terms and conditions specified in the definitive purchase agreement;
- the absence of the occurrence of a material adverse effect (as defined in the Merger Agreement) relating to either AERC or Avista Corp. after the date of the signed agreement; and
- other customary closing conditions.

The Merger Agreement also provides for customary termination rights for each of the Company and AERC, including the right for either party to terminate if the Merger has not been consummated by December 31, 2014 provided, however, that the failure of the Merger to have been consummated on or before December 31, 2014 was not caused by the failure of such party or any affiliate of such party to perform any of its obligations under the Merger Agreement. Upon termination of the Merger Agreement in accordance with its terms, there will be no further liability under the agreement except that nothing shall relieve any party thereto from liability for any breach of the agreement.

There may be certain commitments and contingencies that will be assumed when the merger transaction is consummated; however, Avista Corp. has not fully completed its evaluation of all the potential commitments and contingencies.

For the year ended December 31, 2013, Avista Corp. incurred $1.6 million (pre-tax) of transaction related fees which have been expensed and presented in the Statements of Income in other operating expenses within utility operating expenses. Avista Corp. expects to incur additional transaction related fees upon consummation of the transaction.

NOTE 4. DERIVATIVES AND RISK MANAGEMENT

Energy Commodity Derivatives

Avista Corp. is exposed to market risks relating to changes in electricity and natural gas commodity prices and certain other fuel prices. Market risk is, in general, the risk of fluctuation in the market price of the commodity being traded and is influenced primarily by supply and demand. Market risk includes the fluctuation in the market price of associated derivative commodity instruments. Avista Corp. utilizes derivative instruments, such as forwards, futures, swaps and options in order to manage the various risks relating to these commodity price exposures. The Company has an energy resources risk policy and control procedures to manage these risks. The Company's Risk Management Committee establishes the Company's energy resources risk policy and monitors compliance. The Risk Management Committee is comprised of certain Company officers and other members of management. The Audit Committee of the Company's Board of Directors periodically reviews and discusses enterprise risk management processes, and it focuses on the Company's material financial and accounting risk exposures and the steps management has undertaken to control them.

As part of its 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 the Company's load obligations and the use of these resources to capture available economic value. The Company transacts in wholesale markets by selling and purchasing electric capacity and energy, fuel for electric generation, and contracts related to capacity, energy and fuel. Such transactions are part of the process of matching resources with load obligations and hedging the related financial risks. These transactions range from terms of intra-hour up to multiple years.

Avista Corp. makes 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 and contract terms, and
- resource availability at these points in time based on, among other things, fuel choices and fuel markets, estimates of 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 instruments to match expected resources to expected electric load requirements and reduce our exposure to electricity (or fuel) market price changes. Resource optimization involves generating plant dispatch and scheduling available resources and also includes transactions such as:

- purchasing fuel for generation,

- when economical, selling fuel and substituting wholesale electric purchases, and
- other wholesale transactions to capture the value of generation and transmission resources and fuel delivery capacity contracts.

Avista Corp.'s optimization process includes entering into hedging transactions to manage risks. Transactions include both physical energy contracts and related derivative financial instruments.

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 significant portion of its projected natural gas requirements through forward market transactions and derivative instruments. These transactions may extend as much as four 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.

Natural gas resource optimization activities include:

- wholesale market sales of surplus natural gas supplies,
- optimization of interstate pipeline transportation capacity not needed to serve daily load, and
- purchases and sales of natural gas to optimize use of storage capacity.

The following table presents the underlying energy commodity derivative volumes as of December 31, 2013 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
2014	769	2,156	29,642	145,719	509	3,116	3,504	105,433
2015	397	1,043	4,973	73,580	222	2,542	—	46,840
2016	397	—	2,505	46,150	287	1,634	—	21,320
2017	397	—	675	—	286	—	—	—
2018	397	—	—	—	286	—	—	—
Thereafter	235	—	—	—	158	—	—	—

(1) Physical transactions represent commodity transactions where Avista Corp. will take delivery of either electricity or natural gas and financial transactions represent derivative instruments with no physical delivery, such as futures, swaps or options.

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 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 Contracts

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 and settled within 60 days with U.S. dollars. Avista Corp. hedges a portion of the foreign currency risk by purchasing Canadian currency contracts when such commodity transactions are initiated. This risk has not had a material effect on the Company's financial condition, results of operations or cash flows and these differences in cost related to currency fluctuations were included with natural gas supply costs for ratemaking. The following table summarizes the foreign currency hedges that the Company has entered into as of December 31 (dollars in thousands):

	2013	2012
Number of contracts	23	20
Notional amount (in United States dollars)	$ 8,631	$ 12,621
Notional amount (in Canadian dollars)	9,191	12,502

Interest Rate Swap Agreements

Avista Corp. is affected by fluctuating interest rates related to a portion of its existing debt, and future borrowing requirements. The Finance Committee of the Board of Directors periodically reviews and discusses interest rate risk management processes, and it focuses on the steps management has undertaken to control it. The Risk Management Committee also reviews the interest risk management plan. Avista Corp. manages interest rate exposure by limiting the variable rate exposures to a percentage of total capitalization. Additionally, interest rate risk is managed by monitoring market conditions when timing the issuance of long-term debt and optional debt redemptions and through the use of fixed rate long-term debt with varying maturities. The Company also hedges a portion of its interest rate risk with financial derivative instruments, which may include interest rate swaps and U.S. Treasury lock agreements. These interest rate swaps 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 interest rate swaps that the Company has entered into as of December 31 (dollars in thousands):

Balance Sheet Date	Number of Contracts	Notional Amount	Mandatory Cash Settlement Date
December 31, 2013	2	$ 50,000	2014
	2	45,000	2015
	2	40,000	2016
	1	15,000	2017
	4	95,000	2018
December 31, 2012	2	85,000	2013
	2	50,000	2014
	1	25,000	2015

In June 2013, the Company cash settled two interest rate swap contracts (notional amount of $85.0 million) and received a total of $2.9 million. The interest rate swap contracts were settled in connection with the pricing of $90.0 million of First Mortgage Bonds that were issued in August 2013 (see Note 11). Upon settlement of interest rate swaps, the regulatory asset or liability (included as part of long-term debt) is amortized as a component of interest expense over the term of the associated debt.

The following table presents the fair values and locations of derivative instruments recorded on the Balance Sheet as of December 31, 2013 (in thousands):

		Fair Value						
Derivative	Balance Sheet Location	Gross	Gross	Collateral	Net Asset (Liability) in Balance Sheet	Gross Assets	Gross Liabilities Not Offset	Net Asset
Foreign currency contracts	Derivative instrument assets –Hedges	$ 7	$ (6)	$ —	$ 1	$ —	$ —	$ 1
Interest rate contracts	Derivative instrument assets –Hedges	13,968	—	—	13,968	—	—	13,968
Interest rate contracts	Long-term portion of derivative instrument assets -Hedges	19,575	—	—	19,575	—	—	19,575
Commodity contracts (1)	Derivative instrument assets current	7,416	(4,394)	—	3,022	—	—	3,022
Commodity contracts (1)	Long-term portion of derivative assets	7,610	(6,756)	—	854	—	—	854
Commodity contracts (1)	Derivative instrument liabilities current	23,455	(37,306)	2,976	(10,875)	—	—	(10,875)
Commodity contracts (1)	Long-term portion of derivative liabilities	17,101	(41,213)	5,756	(18,356)	—	—	(18,356)
Total derivative instruments recorded on the balance sheet		$ 89,132	$ (89,675)	$ 8,732	$ 8,189	$ —	$ —	$ 8,189

The following table presents the fair values and locations of derivative instruments recorded on the Balance Sheet as of December 31, 2012 (in thousands):

		Fair Value						
Derivative	Balance Sheet Location	Gross	Gross	Collateral	Net Asset (Liability) in Balance Sheet	Gross Assets	Gross Liabilities Not Offset	Net Asset
Foreign currency contracts	Derivative instrument liabilities –Hedges	$ 7	$ (34)	$ —	$ (27)	$ —	$ —	$ (27)
Interest rate contracts	Derivative instrument liabilities –Hedges	—	(1,406)	—	(1,406)	—	—	(1,406)
Interest rate contracts	Long-term portion of derivative instrument assets -Hedges	7,265	—	—	7,265	—	—	7,265
Commodity contracts (1)	Derivative instrument assets current	10,772	(6,633)	—	4,139	(9,678)	6,572	1,033
Commodity contracts (1)	Long-term portion of derivative assets	18,779	(17,686)	—	1,093	—	—	1,093
Commodity contracts (1)	Derivative instrument	50,227	(89,449)	9,707	(29,515)	9,678	(6,572)	(26,409)

	liabilities current							
Commodity contracts (1)	Long-term portion of derivative liabilities	2,247	(28,558)	—	(26,311)	—	—	(26,311)
Total derivative instruments recorded on the balance sheet		$ 89,297	$ (143,766)	$ 9,707	$ (44,762)	$ —	$ —	$ (44,762)

(1) Avista Corp. has a master netting agreement that governs the transactions of multiple affiliated legal entities under this single master netting agreement. This master netting agreement allows for cross-commodity netting (i.e. netting physical power, physical natural gas, and financial transactions) and cross-affiliate netting for the parties to the agreement. Avista Corp. performs cross-commodity netting for each legal entity that is a party to the master netting agreement for presentation in the Balance Sheets; however, Avista Corp. does not perform cross-affiliate netting because the Company believes that cross-affiliate netting may not be enforceable. Therefore, the requirements for cross-affiliate netting under ASC 210-20-45 are not applicable for Avista Corp. As of December 31, 2013, all derivatives for each affiliated entity under this master netting agreement were in a net liability position. As such, there is no additional netting which requires disclosure.

Exposure to Demands for Collateral

The Company'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 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. The Company actively monitors the exposure to possible collateral calls and takes steps to mitigate capital requirements. As of December 31, 2013, the Company had cash deposited as collateral of $26.1 million and letters of credit of $20.3 million outstanding related to its energy derivative contracts. The Balance Sheet at December 31, 2013 reflects the offsetting of $8.7 million of cash collateral against net derivative positions where a legal right of offset exists. As of December 31, 2012, the Company had cash deposited as collateral of $10.1 million and letters of credit of $28.1 million outstanding related to its energy derivative contracts. The Balance Sheet at December 31, 2012 reflects the offsetting of $9.7 million of cash collateral against net derivative positions where a legal right of offset exists.

Certain of the Company's derivative instruments contain provisions that require the Company to maintain an investment grade credit rating from the major credit rating agencies. If the Company'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 aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a liability position as of December 31, 2013 was $13.3 million. If the credit-risk-related contingent features underlying these agreements had been triggered on December 31, 2013, the Company could have been required to post $12.6 million of additional collateral to its counterparties. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position as of December 31, 2012 was $35.9 million. If the credit-risk-related contingent features underlying these agreements had been triggered on December 31, 2012, the Company could have been required to post $25.8 million of additional collateral to its counterparties.

Credit Risk

Credit risk relates to the potential losses that the Company would incur as a result of non-performance by counterparties of their contractual obligations to deliver energy or make financial settlements. The Company often extends credit to counterparties and customers and is exposed to the risk that it may not be able to collect amounts owed to the Company. Credit risk includes potential counterparty default due to circumstances:

- relating directly to it,
- caused by market price changes, and
- relating to other market participants that have a direct or indirect relationship with such counterparty.

Changes in market prices may dramatically alter the size of credit risk with counterparties, even when conservative credit limits are established. Should a counterparty fail to perform, the Company 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 between Avista Corp. and various counterparties. We also trade energy and related derivative instruments through clearinghouse exchanges.

The Company seeks to mitigate bilateral credit risk by:

- 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,
- carrying out transaction settlements timely and effectively, and
- conducting transactions on exchanges with fully collateralized clearing arrangements that significantly reduce counterparty default risk.

The Company's credit policy includes an evaluation of the financial condition of counterparties. Credit risk management includes collateral requirements or other credit enhancements, such as letters of credit or parent company guarantees. The Company enters into various agreements that address credit risks including standardized agreements that allow for the netting or offsetting of positive and negative exposures.

The Company has concentrations of suppliers and customers in the electric and natural gas industries including:

- electric and natural gas utilities,
- electric generators and transmission providers,
- natural gas producers and pipelines,
- financial institutions including commodity clearing exchanges and related parties, and
- energy marketing and trading companies.

In addition, the Company has concentrations of credit risk related to geographic location as it operates in the western United States and western Canada. These concentrations of counterparties and concentrations of geographic location may impact the Company's overall exposure to credit risk because the counterparties may be similarly affected by changes in conditions.

The Company maintains credit support agreements with certain counterparties and margin calls are periodically made and/or received. Margin calls are triggered when exposures exceed contractual limits or when there are changes in a counterparty's creditworthiness. Price movements in electricity and natural gas can generate exposure levels in excess of these contractual limits. Negotiating for collateral in the form of cash, letters of credit, or performance guarantees is common industry practice.

NOTE 5. JOINTLY OWNED ELECTRIC FACILITIES

The Company has a 15 percent ownership interest in a twin-unit coal-fired generating facility, the Colstrip Generating Project (Colstrip) located in southeastern Montana, and provides financing for its ownership interest in the project. 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 were as follows as of December 31 (dollars in thousands):

	2013	2012
Utility plant in service	$ 349,781	$ 344,958
Accumulated depreciation	(239,538)	(234,126)

NOTE 6. ASSET RETIREMENT OBLIGATIONS

The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the associated costs of the asset retirement obligation 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. Upon retirement of the asset, the Company either settles the retirement obligation for its recorded amount or incurs a gain or loss. The Company records regulatory assets and liabilities for the difference between asset retirement costs currently recovered in rates and asset retirement obligations recorded since asset retirement costs are recovered through rates charged to customers. The regulatory assets do not earn a return.

Specifically, the Company has recorded liabilities for future asset retirement obligations to:

- restore ponds at Colstrip,
- cap a landfill at the Kettle Falls Plant,
- remove plant and restore the land at the Coyote Springs 2 site at the termination of the land lease,
- remove asbestos at the corporate office building, and
- dispose of PCBs in certain transformers.

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

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

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

	2013	2012
Asset retirement obligation at beginning of year	$ 3,168	$ 3,513
Liability settled	(263)	(559)
Accretion expense (income)	(46)	214
Asset retirement obligation at end of year	$ 2,859	$ 3,168

NOTE 7. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

The Company has a defined benefit pension plan covering substantially all regular full-time employees at Avista Corp.. 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. 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 $44.3 million in cash to the pension plan in 2013 and $44.0 million in 2012. The Company expects to contribute $32.0 million in cash to the pension plan in 2014.

In October 2013, the Company revised its defined benefit pension plan such that as of January 1, 2014 the plan is closed to all non-union employees hired or rehired by the Company on or after January 1, 2014. All actively employed non-union employees that were hired prior to January 1, 2014 and are currently covered under the defined benefit pension plan will continue accruing benefits as originally specified in the plan. A new and separate defined contribution 401(k) plan replaced the defined benefit pension plan for all non-union employees hired or rehired on or after January 1, 2014. Under the new defined contribution plan, the Company provides a non-elective contribution as a percentage of each employee's pay based on his or her age. This new defined contribution plan is in addition to the existing 401(k) plan in which the Company matches a portion of the pay deferred by each participant. In addition to the above changes, the Company has also revised its lump sum calculation from its previous lump sum calculation for non-union participants who retire under the defined benefit pension plan to provide non-union retirees on or after January 1, 2014 with a lump sum amount equivalent to the present value of the annuity based upon applicable discount rates.

The Company also has a Supplemental Executive Retirement Plan (SERP) that provides additional pension benefits to executive officers of the Company. The SERP is intended to provide benefits to executive officers whose benefits under the 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):

	2014	2015	2016	2017	2018	Total 2019-2023
Expected benefit payments	$ 25,176	$ 26,735	$ 27,731	$ 28,880	$ 30,379	$ 172,887

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 substantially all of its retired employees. The Company accrues the estimated cost of postretirement benefit obligations during the years that employees provide services. The Company elected to amortize the transition obligation of $34.5 million over a period of 20 years, beginning in 1993. In October 2013, the Company revised the health care benefit plan such that beginning on January 1, 2020, the method for calculating health insurance premiums for non-union retirees under age 65 and active Company employees was revised. The revisions resulted in separate health insurance premium calculations for each group. In addition, for non-union employees hired or rehired on or after January 1, 2014, upon retirement the Company no longer provides a contribution towards his or her medical premiums. The Company will provide access to its retiree medical plan, but the non-union employees hired or rehired on or after January 1, 2014 will pay the full cost of premiums upon retirement.

The Company has a Health Reimbursement Arrangement 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 this plan 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):

	2014	2015	2016	2017	2018	Total 2019-2023
Expected benefit payments	$ 6,969	$ 6,707	$ 7,056	$ 7,120	$ 7,247	$ 35,121

The Company expects to contribute $7.0 million to other postretirement benefit plans in 2014, representing expected benefit payments to be paid during the year. 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, 2013 and 2012 and the components of net periodic benefit costs for the years ended December 31, 2013 and 2012 (dollars in thousands):

	Pension Benefits		Other Post-retirement Benefits	
	2013	2012	2013	2012
Change in benefit obligation:				
Benefit obligation as of beginning of year	$ 584,619	$ 494,192	$ 132,541	$ 104,730
Service cost	19,045	15,551	4,144	2,804
Interest cost	23,896	24,349	5,216	5,056
Actuarial (gain)/loss	(78,234)	72,170	(18,017)	24,543
Plan change	277	—	(10,788)	—
Transfer of accrued vacation	—	—	1,189	336
Benefits paid	(22,599)	(21,643)	(6,036)	(4,928)
Benefit obligation as of end of year	$ 527,004	$ 584,619	$ 108,249	$ 132,541
Change in plan assets:				
Fair value of plan assets as of beginning of year	$ 406,061	$ 328,150	$ 25,288	$ 22,455
Actual return on plan assets	52,502	54,318	4,444	2,833
Employer contributions	44,263	44,000	—	—
Benefits paid	(21,324)	(20,407)	—	—
Fair value of plan assets as of end of year	$ 481,502	$ 406,061	$ 29,732	$ 25,288
Funded status	$ (45,502)	$ (178,558)	$ (78,517)	$ (107,253)
Unrecognized net actuarial loss	107,043	223,308	56,885	94,202
Unrecognized prior service cost	278	319	(707)	(856)
Prepaid (accrued) benefit cost	61,819	45,069	(22,339)	(13,907)
Additional liability	(107,321)	(223,627)	(56,178)	(93,346)
Accrued benefit liability	$ (45,502)	$ (178,558)	$ (78,517)	$ (107,253)
Accumulated pension benefit obligation	$ 464,432	$ 505,695	—	—
Accumulated postretirement benefit obligation:				
For retirees			$ 52,384	$ 49,232
For fully eligible employees			$ 24,320	$ 35,570
For other participants			$ 31,545	$ 47,739
Included in accumulated other comprehensive loss (income) (net of tax):				
Unrecognized prior service cost	$ 180	$ 207	$ (7,472)	$ (556)
Unrecognized net actuarial loss	69,578	145,150	43,988	61,231
Total	69,758	145,357	36,516	60,675
Less regulatory asset	(64,925)	(138,184)	(37,116)	(60,981)
Accumulated other comprehensive loss (income)	$ 4,833	$ 7,173	$ (600)	$ (306)

	Pension Benefits		Other Post-retirement Benefits	
	2013	2012	2013	2012
Weighted average assumptions as of December 31:				

Discount rate for benefit obligation	5.10%	4.15%	5.02%	4.15%
Discount rate for annual expense	4.15%	5.04%	4.15%	4.98%
Expected long-term return on plan assets	6.60%	6.95%	6.35%	6.55%
Rate of compensation increase	4.96%	4.89%		
Medical cost trend pre-age 65 – initial			7.00%	7.00%
Medical cost trend pre-age 65 – ultimate			5.00%	5.00%
Ultimate medical cost trend year pre-age 65			2020	2019
Medical cost trend post-age 65 – initial			7.50%	7.50%
Medical cost trend post-age 65 – ultimate			5.00%	5.00%
Ultimate medical cost trend year post-age 65			2021	2021

	Pension Benefits		Other Post-retirement Benefits	
	2013	2012	2013	2012
Components of net periodic benefit cost:				
Service cost	$ 19,045	$ 15,551	$ 4,144	$ 2,804
Interest cost	23,896	24,349	5,216	5,056
Expected return on plan assets	(27,671)	(23,810)	(1,606)	(1,471)
Transition obligation recognition	—	—	—	505
Amortization of prior service cost	319	346	(149)	(149)
Net loss recognition	13,199	11,637	5,674	5,020
Net periodic benefit cost	$ 28,788	$ 28,073	$ 13,279	$ 11,765

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 managing/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, absolute return and commodity funds. In seeking to obtain the desired return to fund 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:

	2013	2012
Equity securities	47%	51%
Debt securities	31%	31%
Real estate	6%	5%
Absolute return	12%	10%
Other	4%	3%

The market-related 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, are fair-valued by the investment manager based upon other inputs (including valuations of securities that are comparable in coupon, rating, maturity and industry). Investments in common/collective trust funds are presented at estimated fair value, which is determined based on the unit value of the fund. Unit value is determined by an independent trustee, which sponsors the fund, by dividing the fund's net assets by its units outstanding at the valuation date. The fair value of the closely held investments and partnership interests is based upon the allocated share of the fair value of the underlying assets as well as the allocated share of the undistributed profits and losses, including realized and unrealized gains and losses.

The market-related value of pension plan assets invested in real estate was determined by the investment manager based on three basic approaches:

- properties are externally appraised on an annual basis by independent appraisers, additional appraisals may be performed as warranted by specific asset or market conditions,
- property valuations are reviewed quarterly and adjusted as necessary, and
- loans are reflected at fair value.

The market-related value of pension plan assets was determined as of December 31, 2013 and 2012.

The following table discloses by level within the fair value hierarchy (see Note 14 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2013 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Mutual funds:				
Fixed income securities	$ 86,481	$ 310	$ —	$ 86,791
U.S. equity securities	152,831	—	—	152,831
International equity securities	85,942	—	—	85,942
Absolute return (1)	23,599	—	—	23,599
Common/collective trusts:				
Fixed income securities	—	55,872	—	55,872
Real estate	—	—	19,735	19,735
Partnership/closely held investments:				
Absolute return (1)	—	—	34,151	34,151
Private equity funds (3)	—	—	377	377
Commodities (2)	—	18,331	—	18,331
Real estate	—	—	3,873	3,873
Total	$ 348,853	$ 74,513	$ 58,136	$ 481,502

The following table discloses by level within the fair value hierarchy (see Note 14 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2012 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Mutual funds:				
Fixed income securities	$ 83,037	$ —	$ —	$ 83,037
U.S. equity securities	135,436	—	—	135,436
International equity securities	79,448	—	—	79,448
Absolute return (1)	20,764	—	—	20,764
Commodities (2)	8,258	—	—	8,258
Common/collective trusts:				
Fixed income securities	—	43,107	—	43,107
Real estate	—	—	17,596	17,596
Partnership/closely held investments:				
Absolute return (1)	—	—	17,755	17,755
Private equity funds (3)	—	—	660	660
Total	$ 326,943	$ 43,107	$ 36,011	$ 406,061

(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.

(2) This investment is in derivatives linked to commodity indices to gain exposure to the commodity markets. These positions are fully collateralized with debt securities.

(3) This category includes private equity funds that invest primarily in U.S. companies.

The table below discloses the summary of changes in the fair value of the pension plan's Level 3 assets for the year ended December 31, 2013 (dollars in thousands):

	Common/collective trusts	Partnership/closely held investments		
	Real	Absolute	Private equity	Real estate
Balance, as of January 1, 2013	$ 17,596	$ 17,755	$ 660	$ —
Realized gains	—	—	(323)	—
Unrealized gains (losses)	2,139	2,396	345	113
Purchases (sales), net	—	14,000	(305)	3,760
Balance, as of December 31, 2013	$ 19,735	$ 34,151	$ 377	$ 3,873

The table below discloses the summary of changes in the fair value of the pension plan's Level 3 assets for the year ended December 31, 2012 (dollars in thousands):

	Common/collective trusts	Partnership/closely held investments	
	Real estate	Absolute return	Private equity funds
Balance, as of January 1, 2012	$ 8,598	$ 16,587	$ 808
Realized gains (losses)	411	—	108
Unrealized gains (losses)	1,087	1,168	80
Purchases (sales), net	7,500	—	(336)
Balance, as of December 31, 2012	$ 17,596	$ 17,755	$ 660

The market-related value of other postretirement 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 last reported 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, are fair-valued by the investment manager 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 2013 and 62 percent equity securities and 38 percent debt securities in 2012.

The market-related value of other postretirement plan assets was determined as of December 31, 2013 and 2012.

The following table discloses by level within the fair value hierarchy (see Note 14 for a description of the fair value hierarchy) of other postretirement plan assets measured and reported as of December 31, 2013 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 4	$ —	$ 4
Mutual funds:				
Fixed income securities	11,645	—	—	11,645
U.S. equity securities	11,831	—	—	11,831
International equity securities	6,252	—	—	6,252
Total	$ 29,728	$ 4	$ —	$ 29,732

The following table discloses by level within the fair value hierarchy (see Note 14 for a description of the fair value hierarchy) of other postretirement plan assets measured and reported as of December 31, 2012 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 6	$ —	$ 6
Mutual funds:				
Fixed income securities	9,314	—	—	9,314
U.S. equity securities	10,266	—	—	10,266
International equity securities	5,702	—	—	5,702
Total	$ 25,282	$ 6	$ —	$ 25,288

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point increase in the assumed health care cost trend rate for each year would increase the accumulated postretirement benefit obligation as of December 31, 2013 by $3.8 million and the service and interest cost by $0.8 million. A one-percentage-point decrease in the assumed health care cost trend rate for each year would decrease the accumulated postretirement benefit obligation as of December 31, 2013 by $3.1 million and the service and interest cost by $0.6 million.

The Company has a salary deferral 401(k) plans that is a defined contribution plan and cover substantially all employees. Employees can make contributions to their respective accounts in the plan 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 plan.

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

	2013	2012
Employer 401(k) matching contributions	$ 6,157	$ 5,813

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):

	2013	2012
Deferred compensation assets and liabilities	$ 9,170	$ 8,806

NOTE 8. ACCOUNTING FOR 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.

As of December 31, 2013, the Company had $5.9 million of state tax credit carryforwards. State tax credits expire from 2016 to 2027. The Company recognizes the effect of state tax credits generated from utility plant as they are utilized.

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.

The Company and its eligible subsidiaries file consolidated federal income tax returns. The Company also files state income tax returns in certain jurisdictions, including Idaho, Oregon and Montana. Subsidiaries are charged or credited with the tax effects of their operations on a stand-alone basis. The Internal Revenue Service (IRS) has completed its examination of all tax years through 2009 and all issues were resolved related to these years. The IRS has not completed an examination of the Company's 2010 through 2012 federal income tax returns. The Company does not believe that any open tax years for federal or state income taxes could result in any adjustments that would be significant to the financial statements.

The Company did not incur any penalties on income tax positions in 2013 or 2012.

The Company had net regulatory assets related to the probable recovery of certain deferred income tax liabilities from customers through future rates as of December 31 (dollars in thousands):

	2013	2012
Regulatory assets for deferred income taxes	$ 71,421	$ 79,406

NOTE 9. ENERGY PURCHASE CONTRACTS

Avista Corp. has contracts for the purchase of fuel for thermal generation, natural gas for resale and various agreements for the purchase or exchange of electric energy with other entities. The termination dates of the contracts range from one month to the year 2042. 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):

	2013	2012
Utility power resources	$ 524,810	$ 523,416

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):

	2014	2015	2016	2017	2018	Thereafter	Total
Power resources	$ 201,693	$ 125,072	$ 112,570	$ 110,405	$ 106,200	$ 874,990	$ 1,530,930
Natural gas resources	102,651	64,860	46,665	43,011	37,570	482,986	777,743
Total	$ 304,344	$ 189,932	$ 159,235	$ 153,416	$ 143,770	$ 1,357,976	$ 2,308,673

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 (based in part on the debt service requirements of the PUD) 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.

In addition, Avista Corp. has operating agreements, settlements and other contractual obligations to see the output of its generating facilities and transmission and distribution services. The following table details future contractual commitments under these agreements (dollars in thousands):

	2014	2015	2016	2017	2018	Thereafter	Total
Contractual obligations	$ 30,197	$ 27,236	$ 30,543	$ 29,199	$ 23,534	$ 211,392	$ 352,101

NOTE 10. NOTES PAYABLE

Avista Corp. has a committed line of credit with various financial institutions in the total amount of $400.0 million with an expiration date of February 2017.

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, 2013, 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):

	2013	2012
Balance outstanding at end of period	$ 171,000	$ 52,000
Letters of credit outstanding at end of period	$ 27,434	$ 35,885
Average interest rate at end of period	1.02%	1.12%

As of December 31, 2013 the borrowings outstanding under Avista Corp.'s committed line of credit were classified as short-term borrowings on the Balance Sheet.

NOTE 11. BONDS

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

Maturity Year	Description	Interest Rate	2013	2012
2013	First Mortgage Bonds	1.68%	$ —	$ 50,000

2016	First Mortgage Bonds	0.84%	90,000	—
2018	First Mortgage Bonds	5.95%	250,000	250,000
2018	Secured Medium-Term Notes	7.39%-7.45%	22,500	22,500
2019	First Mortgage Bonds	5.45%	90,000	90,000
2020	First Mortgage Bonds	3.89%	52,000	52,000
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 (2)	(2)	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
2047	First Mortgage Bonds	4.23%	80,000	80,000
	Total secured bonds		1,376,700	1,336,700
	Settled interest rate swaps (3)		(23,560)	(27,900)
	Secured Pollution Control Bonds held by Avista Corporation (1) (2)		(83,700)	(83,700)
	Total bonds		$ 1,269,440	$ 1,225,100

(1) In December 2010, $66.7 million of the City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) due 2032, which had been held by Avista Corp. since 2008, were refunded by a new bond issue (Series 2010A). 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 December 2010, $17.0 million of the City of Forsyth, Montana Pollution Control Revenue Refunding Bonds, (Avista Corporation Colstrip Project) due 2034, which had been held by Avista Corp. since 2009, were refunded by a new bond issue (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, the 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 Sheet.

(3) Upon settlement of interest rate swaps, these are recorded as a regulatory asset or liability and included as part of long-term debt above. They are amortized as a component of interest expense over the life of the associated debt and included as a part of the Company's cost of debt calculation for ratemaking purposes.

In August 2013, Avista Corp. entered into a $90.0 million term loan agreement with an institutional investor that bears an annual interest rate of 0.84 percent and matures in 2016. The term loan agreement is secured by non-transferable First Mortgage Bonds of the Company issued to the agent bank that will only become due and payable in the event, and then only to the extent, that the Company defaults on its obligations under the term loan agreement. The net proceeds from the $90.0 million term loan agreement were used to repay a portion of corporate indebtedness in anticipation of $50.0 million in First Mortgage Bonds that matured in December 2013.

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

	2014	2015	2016	2017	2018	Thereafter	Total
Debt maturities	$ —	$ —	$ 90,000	$ —	$ 272,500	$ 982,047	$ 1,344,547

Substantially all utility properties owned by the Company are subject to the lien of the Company's mortgage indenture. Under the Mortgage and Deed of Trust securing the Company's First Mortgage Bonds (including Secured Medium-Term Notes), the Company may issue additional First Mortgage Bonds in an aggregate principal amount equal to the sum of: 1) 66-2/3 percent of the cost or fair value (whichever is lower) of property additions which have not previously been made the basis of any application under the Mortgage, or 2) an equal principal amount of retired First Mortgage Bonds which have not previously been made the basis of any application under the Mortgage, or 3) deposit of cash. However, the Company 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 Company's "net earnings" (as defined in the Mortgage) for any period of 12 consecutive calendar months out of the preceding 18 calendar months 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, 2013, property additions and retired bonds would have allowed, and the net earnings test would not have prohibited, the issuance of $916.3 million in aggregate principal amount of additional First Mortgage Bonds.

See Note 10 for information regarding First Mortgage Bonds issued to secure the Company's obligations under its committed line of credit agreement.

NOTE 12. ADVANCES FROM ASSOCIATED COMPANIES

In 1997, the Company issued Floating Rate Junior Subordinated Deferrable Interest Debentures, Series B, with a principal amount of $51.5 million to Avista Capital II, an affiliated business trust formed by the Company. Avista Capital II issued $50.0 million of Preferred Trust Securities with a floating distribution rate of LIBOR plus 0.875 percent, calculated and reset quarterly. The distribution rates paid were as follows during the years ended December 31:

	2013	2012
Low distribution rate	1.11%	1.19%
High distribution rate	1.19%	1.40%
Distribution rate at the end of the year	1.11%	1.19%

Concurrent with the issuance of the Preferred Trust Securities, Avista Capital II issued $1.5 million of Common Trust Securities to the Company. These debt securities may be redeemed at the option of Avista Capital II on or after June 1, 2007 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 13. LEASES

The Company has multiple lease arrangements involving various assets, with minimum terms ranging from 1 to forty-five years. Rental expense under operating leases was as follows for the years ended December 31 (dollars in thousands):

	2013	2012
Rental expense	$ 2,797	$ 3,274

Future minimum lease payments required under operating leases having initial or remaining noncancelable lease terms in excess of one year as of December 31 were as follows (dollars in thousands):

	2014	2015	2016	2017	2018	Thereafter	Total
Minimum payments required	$ 1,773	$ 582	$ 223	$ 179	$ 168	$ 2,651	$ 5,576

NOTE 14. 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 measurement) and the lowest priority to unobservable inputs (Level 3 measurement).

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, 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):

	2013		2012	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Bonds (Level 2)	$ 951,000	$ 1,054,512	$ 951,000	$ 1,164,639
Bonds (Level 3)	342,000	329,581	302,000	320,892
Advances from associated companies (Level 3)	51,547	37,114	51,547	43,686

These estimates of fair value were primarily based on available market information.

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, 2013 and 2012 at fair value on a recurring basis (dollars in thousands):

Counterparty and Cash Collateral

	Level 1	Level 2	Level 3	Netting (1)	Total
December 31, 2013					
Assets:					
Energy commodity derivatives	$ —	$ 55,243	$ —	$ (51,367)	$ 3,876
Level 3 energy commodity derivatives:					
Power exchange agreement	—	—	339	(339)	—
Foreign currency derivatives	—	7	—	(6)	1
Interest rate swaps	—	33,543	—	—	33,543
Deferred compensation assets:					
Fixed income securities	1,960	—	—	—	1,960
Equity securities	6,470	—	—	—	6,470
Total	$ 8,430	$ 88,793	$ 339	$ (51,712)	$ 45,850
Liabilities:					
Energy commodity derivatives	$ —	$ 72,895	$ —	$ (60,099)	$ 12,796
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	1,219	—	1,219
Power exchange agreement	—	—	14,780	(339)	14,441
Power option agreement	—	—	775	—	775
Foreign currency derivatives	—	6	—	(6)	—
Total	$ —	$ 72,901	$ 16,774	$ (60,444)	$ 29,231

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
December 31, 2012					
Assets:					
Energy commodity derivatives	$ —	$ 81,640	$ —	$ (76,408)	$ 5,232
Level 3 energy commodity derivatives:					
Power exchange agreement	—	—	385	(385)	—
Foreign currency derivatives	—	7	—	(7)	—
Interest rate swaps	—	7,265	—	—	7,265
Deferred compensation assets:					
Fixed income securities	2,010	—	—	—	2,010
Equity securities	5,955	—	—	—	5,955
Total	$ 7,965	$ 88,912	$ 385	$ (76,800)	$ 20,462
Liabilities:					
Energy commodity derivatives	$ —	$ 119,390	$ —	$ (86,115)	$ 33,275
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	2,379	—	2,379
Power exchange agreement	—	—	19,077	(385)	18,692
Power option agreement	—	—	1,480	—	1,480
Foreign currency derivatives	—	34	—	(7)	27
Interest rate swaps	—	1,406	—	—	1,406
Total	$ —	$ 120,830	$ 22,936	$ (86,507)	$ 57,259

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.

Avista Corp. enters into forward contracts to purchase or sell a specified amount of energy at a specified time, or during a specified period, in the future. These contracts are entered into as part of Avista Corp.'s management of loads and resources and certain contracts are considered derivative instruments. The difference between the amount of derivative assets and liabilities disclosed in respective levels and the amount of derivative assets and liabilities disclosed on the Balance Sheets is due to netting arrangements with certain counterparties. The Company uses quoted market prices and forward price curves to estimate the fair value of utility derivative commodity instruments included in Level 2. In particular, electric derivative valuations are performed using broker quotes, adjusted for periods in between quotable periods. Natural gas derivative valuations are estimated using New York Mercantile Exchange (NYMEX) pricing for similar instruments, adjusted for basin differences, using broker quotes. Where observable inputs are available for substantially the full term of the contract, the derivative asset or liability is included in Level 2.

Deferred compensation assets and liabilities represent funds held by the Company in a Rabbi Trust for an executive deferral plan. These funds consist of actively traded equity and bond funds with quoted prices in active markets. The balance disclosed in the table above excludes cash and cash equivalents of $0.7 million as of December 31, 2013 and $0.8 million as of December 31, 2012.

Level 3 Fair Value

For the power exchange agreement, the Company compares the Level 2 brokered quotes and forward price curves described above to an internally developed forward price which is based on the average operating and maintenance (O&M) charges from four surrogate nuclear power plants around the country for the current year. Because the nuclear power plant O&M charges are only known for one year, all forward years are estimated assuming an annual escalation. In addition to the forward price being estimated using unobservable inputs, the Company also estimates the volumes of the transactions that will take place in the future based on historical average transaction volumes per delivery year (November to April). Significant increases or decreases in any of these inputs in isolation would result in a significantly higher or lower fair value measurement. Generally, a change in the current year O&M charges for the surrogate plants is accompanied by a directionally similar change in O&M charges in future years. There is generally not a correlation between external market prices and the O&M charges used to develop the internal forward price.

For the power commodity option agreement, the Company uses the Black-Scholes-Merton valuation model to estimate the fair value, and this model includes significant inputs not observable or corroborated in the market. These inputs include 1) the strike price (which is an internally derived price based on a combination of generation plant heat rate factors, natural gas market pricing, delivery and other O&M charges, 2) estimated delivery volumes for years beyond 2014, and 3) volatility rates for periods beyond October 2016. Significant increases or decreases in any of these inputs in isolation would result in a significantly higher or lower fair value measurement. Generally, changes in overall commodity market prices and volatility rates are accompanied by directionally similar changes in the strike price and volatility assumptions used in the calculation.

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. As of December 31, 2013, all contractual purchases have been made by Avista Corp. under the natural gas commodity exchange agreement; therefore, the Company no longer estimates forward purchase volumes and forward purchase prices as these are not significant inputs to the calculation.

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, 2013 (dollars in thousands):

	Fair Value (Net) at December 31, 2013	Valuation Technique	Unobservable Input	Range
Power exchange agreement	$ (14,441)	Surrogate facility pricing	O&M charges	$30.18-$53.90/MWh (1)
			Escalation factor	3% - 2014 to 2019
			Transaction volumes	234,064 - 397,116 MWhs
Power option agreement	(775)	Black-Scholes-Merton	Strike price	$55.62/MWh - 2016
				$65.31/MWh - 2019
			Delivery volumes	157,517 - 287,147 MWhs
			Volatility rates	0.20 (2)
Natural gas exchange agreement	(1,219)	Internally derived weighted average cost of gas	Forward purchase prices	(3)
			Forward sales prices	$3.98 - $4.57/mmBTU
			Purchase volumes	(3)
			Sales volumes	150,000 - 310,000 mmBTUs

(1) The average O&M charges for the delivery year beginning in November 2013 were $40.93 per MWh. For rate-making purposes the average O&M calculations vary slightly between regulatory jurisdictions. For Washington, the average O&M charges were $42.44 and the average O&M charges for Idaho were $40.93 for the delivery year beginning in 2013.

(2) The estimated volatility rate of 0.20 is compared to actual quoted volatility rates of 0.31 for 2014 to 0.20 in October 2016.

(3) As of December 31, 2013, all contractual purchases have been made by Avista Corp. under the original natural gas exchange agreement; therefore, the Company did not estimate forward purchase volumes and forward purchase prices as these are not significant inputs to the calculation at December 31, 2013. On January 31, 2014, the Company executed an extension to this agreement; therefore, during the first quarter of 2014, forward purchase volumes and forward purchase prices will again be a significant input to the calculation and the Company will resume estimating these amounts.

Avista Corp.'s risk management team and accounting team are responsible for developing the valuation methods described above and both groups report to the Chief Financial Officer. The valuation methods, the significant inputs, and the resulting fair values described above are reviewed on at least a quarterly basis by the risk management team and the accounting team 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	Power Option	Total
Year ended December 31, 2013:				
Balance as of January 1, 2013	$ (2,379)	$ (18,692)	$ (1,480)	$ (22,551
Total gains or losses (realized/unrealized):				
Included in net income	—	—	—	—
Included in other comprehensive income	—	—	—	—
Included in regulatory assets/liabilities (1)	2,298	1,017	705	4,020
Purchases	—	—	—	—
Issuance	—	—	—	—
Settlements	(1,138)	3,234	—	2,096
Transfers to/from other categories	—	—	—	—
Ending balance as of December 31, 2013	$ (1,219)	$ (14,441)	$ (775)	$ (16,435
Year ended December 31, 2012:				
Balance as of January 1, 2012	$ (1,688)	$ (9,910)	$ (1,260)	$ (12,858)
Total gains or losses (realized/unrealized):				
Included in net income	—	—	—	—
Included in other comprehensive income	—	—	—	—
Included in regulatory assets/liabilities (1)	343	(15,236)	(220)	(15,113)
Purchases	—	—	—	—
Issuance	—	—	—	—
Settlements	(1,034)	6,454	—	5,420
Transfers from other categories	—	—	—	—
Ending balance as of December 31, 2012	$ (2,379)	$ (18,692)	$ (1,480)	$ (22,551)

(1) The UTC and the IPUC issued accounting orders authorizing Avista Corp. to offset 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. The orders provide for Avista Corp. to not recognize the unrealized gain or loss on utility derivative commodity instruments in the Statements of Income. Realized gains or losses are recognized in the period of delivery, subject to approval for recovery through retail rates. Realized gains and losses, subject to regulatory approval, result in adjustments to retail rates through purchased gas cost adjustments, the ERM in Washington, the PCA mechanism in Idaho, and periodic general rates cases.

NOTE 15. COMMON STOCK

The Company has a Direct Stock Purchase and Dividend Reinvestment Plan under which the Company's shareholders may automatically reinvest their dividends and make optional cash payments for the purchase of the Company's common stock at current market value.

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, and

- the hydroelectric licensing requirements of section 10(d) of the FPA (see Note 1).

The Company declared the following dividends for the year ended December 31:

	2013	2012
Dividends paid per common share	$ 1.22	$ 1.16

In August 2012, the Company entered into two sales agency agreements under which the Company may sell up to 2,726,390 shares of its common stock from time to time. There were no shares issued under these agreements during 2013 and as of December 31, 2013, the Company had 1,795,199 shares available to be issued under these agreements.

Shares issued under sales agency agreements were as follows in the year ended December 31:

	2013	2012
Shares issued under sales agency agreement	—	931,191

The Company has 10 million authorized shares of preferred stock. The Company did not have any preferred stock outstanding as of December 31, 2013 and 2012.

NOTE 16. STOCK COMPENSATION PLANS

Avista Corp.

1998 Plan

In 1998, the Company adopted, and shareholders approved, the Long-Term Incentive Plan (1998 Plan). Under the 1998 Plan, certain key employees, officers and non-employee directors of the Company and its subsidiaries may be granted stock options, stock appreciation rights, stock awards (including restricted stock) and other stock-based awards and dividend equivalent rights. The Company has available a maximum of 4.5 million shares of its common stock for grant under the 1998 Plan. As of December 31, 2013, 0.9 million shares were remaining for grant under this plan.

2000 Plan

In 2000, the Company adopted a Non-Officer Employee Long-Term Incentive Plan (2000 Plan), which was not required to be approved by shareholders. The provisions of the 2000 Plan are essentially the same as those under the 1998 Plan, except for the exclusion of non-employee directors and executive officers of the Company. The Company has available a maximum of 2.5 million shares of its common stock for grant under the 2000 Plan. However, the Company currently does not plan to issue any further options or securities under the 2000 Plan. As of December 31, 2013, 1.9 million shares were remaining for grant under this plan.

Stock Compensation

The Company records compensation cost relating to share-based payment transactions in the financial statements based on the fair value of the equity or liability instruments issued. 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):

	2013	2012
Stock-based compensation expense	$ 6,218	$ 5,792
Income tax benefits	2,176	2,027

Stock Options

The following summarizes stock options activity under the 1998 Plan and the 2000 Plan for the years ended December 31:

		2013		2012
Number of shares under stock options:				
Options outstanding at beginning of year		3,000		92,499
Options granted		—		—
Options exercised		(3,000)		(89,499)
Options canceled		—		—
Options outstanding and exercisable at end of year		—		3,000
Weighted average exercise price:				
Options exercised	$	12.41	$	10.63
Options canceled	$	—	$	—
Options outstanding and exercisable at end of year	$	—	$	12.41
Cash received from options exercised (in thousands)	$	37	$	951
Intrinsic value of options exercised (in thousands)	$	40	$	1,349
Intrinsic value of options outstanding (in thousands)	$	—	$	35

There are no longer any stock options outstanding as of December 31, 2013 and the Company does not have any plans to issue additional stock options in the near future.

Restricted Shares

Restricted share awards vest in equal thirds each year over a three-year period and are payable in Avista Corp. common stock at the end of each year if the service condition is met. In addition to the service condition, the Company must meet a return on equity target in order for the CEO's restricted shares to vest. During the vesting period, employees are entitled to dividend equivalents which are paid when dividends on the Company's common stock are declared. Restricted stock is valued at the close of market of the Company's common stock on the grant date. The weighted average remaining vesting period for the Company's restricted shares outstanding as of December 31, 2013 was 0.7 years.

The following table summarizes restricted stock activity for the years ended December 31:

		2013		2012
Unvested shares at beginning of year		117,118		93,482
Shares granted		44,556		70,281
Shares canceled		(1,802)		(790)
Shares vested		(55,456)		(45,855)
Unvested shares at end of year		104,416		117,118
Weighted average fair value at grant date	$	26.04	$	25.83
Unrecognized compensation expense at end of year (in thousands)	$	1,199	$	1,428
Intrinsic value, unvested shares at end of year (in thousands)	$	2,943	$	2,824
Intrinsic value, shares vested during the year (in thousands)	$	1,363	$	1,173

Performance Shares

Performance share awards vest after a period of three years and are payable in cash or Avista Corp. common stock at the end of the three-year period. Performance share awards entitle the recipients to dividend equivalent rights, are subject to forfeiture under certain circumstances, and are subject to meeting a specific performance criterion. Based on the attainment of the performance criterion, the amount of cash paid or common stock issued will range from 0 to 200 percent of the performance shares granted depending on the change in the value of the Company's common stock relative to an external benchmark. Dividend equivalent rights are accumulated and paid out only on shares that eventually vest.

Performance share awards entitle the grantee to shares of common stock or cash payable once the service condition is satisfied. Based on attainment of the performance criteria, grantees may receive 0 to 200 percent of the original shares granted. The performance criterion used is the Company's Total Shareholder Return performance over a three-year period as compared against other utilities; this is considered a market-based condition. Performance shares may be settled in common stock or cash at the discretion of the Company. Historically, the Company has settled these awards through issuance of stock and intends to continue this practice. These awards vest at the end of the three-year period. Performance shares are equity awards with a market-based condition, which results in the compensation cost for these awards being recognized over the requisite service period, provided that the requisite service period is rendered, regardless of when, if ever, the market condition is satisfied.

The Company measures (at the grant date) the estimated fair value of performance shares awarded. The fair value of each performance share award was estimated on the date of grant using a statistical model that incorporates the probability of meeting performance targets based on historical returns relative to a peer group. Expected volatility was based on the historical volatility of Avista Corp. common stock over a three-year period. The expected term of the performance shares is three years based on the performance cycle. The risk-free interest rate was based on the U.S. Treasury yield at the time of grant. The compensation expense on these awards will only be adjusted for changes in forfeitures.

The following summarizes the weighted average assumptions used to determine the fair value of performance shares and related compensation expense as well as the resulting estimated fair value of performance shares granted:

	2013	2012
Risk-free interest rate	0.4%	0.3%
Expected life, in years	3	3
Expected volatility	19.1%	22.7%
Dividend yield	4.6%	4.5%
Weighted average grant date fair value (per share)	$ 23.30	$ 26.06

The fair value includes both performance shares and dividend equivalent rights.

The following summarizes performance share activity:

	2013	2012
Opening balance of unvested performance shares	359,700	351,345
Performance shares granted	175,000	181,000
Performance shares canceled	(13,298)	(4,544)
Performance shares vested	(176,718)	(168,101)
Ending balance of unvested performance shares	344,684	359,700
Intrinsic value of unvested performance shares (in thousands)	$ 9,717	$ 8,672
Unrecognized compensation expense (in thousands)	$ 3,651	$ 3,800

The weighted average remaining vesting period for the Company's performance shares outstanding as of December 31, 2013 was 1.5 years. Unrecognized compensation expense as of December 31, 2013 includes only the amount attributable to the equity portion of the performance share awards and will be recognized during 2014 and 2015.

The following summarizes the impact of the market condition on the vested performance shares:

	2013	2012
Performance shares vested	176,718	168,101
Impact of market condition on shares vested	(176,718)	(168,101)

Shares of common stock earned	—	—
Intrinsic value of common stock earned (in thousands)	$ —	$ —

Shares earned under this plan are distributed to participants in the quarter following vesting.

Outstanding performance share awards include a dividend component that is paid in cash. This component of the performance share grants is accounted for as a liability award. These liability awards are revalued on a quarterly basis taking into account the number of awards outstanding, historical dividend rate, and the change in the value of the Company's common stock relative to an external benchmark. Over the life of these awards, the cumulative amount of compensation expense recognized will match the actual cash paid. As of December 31, 2013 and 2012, the Company had recognized cumulative compensation expense and a liability of $0.9 million and $0.7 million related to the dividend component on the outstanding and unvested performance share grants.

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.

Federal Energy Regulatory Commission Inquiry

In April 2004, the Federal Energy Regulatory Commission (FERC) approved the contested Agreement in Resolution of Section 206 Proceeding (Agreement in Resolution) between Avista Corp., Avista Energy and the FERC's Trial Staff which stated that there was: (1) no evidence that any executives or employees of Avista Corp. or Avista Energy knowingly engaged in or facilitated any improper trading strategy during 2000 and 2001; (2) no evidence that Avista Corp. or Avista Energy engaged in any efforts to manipulate the western energy markets during 2000 and 2001; and (3) no finding that Avista Corp. or Avista Energy withheld relevant information from the FERC's inquiry into the western energy markets for 2000 and 2001 (Trading Investigation). The FERC's decisions approving the Agreement in Resolution are pending before the United States Court of Appeals for the Ninth Circuit (Ninth Circuit). In May 2004, the FERC provided notice that Avista Energy was no longer subject to an investigation reviewing certain bids above $250 per MW in the short-term energy markets operated by the California Independent System Operator (CalISO) and the California Power Exchange (CalPX) from May 1, 2000 to October 2, 2000 (Bidding Investigation). That matter is also pending before the Ninth Circuit.

As discussed in "California Refund Proceeding" below, in November 2013, Avista Corp. and Avista Energy arrived at a settlement in principle with Pacific Gas & Electric (PG&E), Southern California Edison, San Diego Gas & Electric, the California Attorney General (AG), the California Department of Water Resources (CERS), and the California Public Utilities Commission that would resolve these matters and obviate the need for further litigation. The Company filed the settlement at the FERC for its approval on March 7, 2014. The Company does not expect that this matter will have a material adverse effect on its financial condition, results of operations or cash flows.

California Refund Proceeding

In July 2001, the FERC ordered an evidentiary hearing to determine the amount of refunds due to California energy buyers for purchases made in the spot markets operated by the CalISO and the CalPX during the period from October 2, 2000 to June 20, 2001 (Refund Period). Proposed refunds are based on the calculation of mitigated market clearing prices for each hour. The FERC ruled that if the refunds required by the formula would cause a seller to recover less than its actual costs for the Refund Period, sellers may document these costs and limit their refund liability commensurately. In 2011, the FERC approved Avista Energy's cost filing, a decision that is now before the Ninth Circuit.

In August 2006, the Ninth Circuit remanded to the FERC its decision not to consider an FPA section 309 remedy for tariff violations prior to October 2, 2000. In May 2011, the FERC clarified the issues set for hearing for the period May 1, 2000 - October 1, 2000 (Summer Period): (1) which market practices and behaviors constitute a violation of the then-current CalISO, CalPX, and individual seller's tariffs and FERC orders; (2) whether any of the sellers named as respondents in this proceeding engaged in those tariff violations; and (3) whether any such tariff violations affected the market clearing price. The FERC also gave the California parties an opportunity to show that exchange transactions with the CalISO during the Refund Period were not just and reasonable. During a FERC hearing in 2012, the Presiding Administrative Law Judge (ALJ) issued a partial initial decision granting Avista Corp.'s motion for summary disposition, based on the stipulation by the California Parties that there are no allegations of tariff violations made against Avista Corp. in this proceeding and therefore no tariff violations by Avista Corp. that affected the market clearing price in any hour during the Summer Period. On November 2, 2012, the FERC issued an order affirming the partial initial decision and dismissing Avista Corp. from the proceeding, thereby terminating all claims against Avista Corp. for the Summer Period. In the same order, the FERC also held that a market-wide remedy would not be appropriate with regard to any respondent during the Summer Period. The FERC stated that it is clear that the Ninth Circuit did not mandate a specific remedy on remand and, instead, left it to the FERC's discretion to determine which remedy would be appropriate. On February 15, 2013, the ALJ issued an initial decision ruling that the California Parties met their burden in the case against Avista Energy by relying on "screens" that identified transactions that potentially could have signified tariff violations. The initial decision did not discuss evidence offered by Avista Energy, on an hour-by-hour basis, rebutting the alleged violations. With respect to Avista Energy's one exchange transaction with the CalISO during the Refund Period, the judge made no findings with respect to the justness and reasonableness of that transaction, but nonetheless determined that Avista Energy owed approximately $0.2 million in refunds with regard to the transaction.

In November of 2013, Avista Corp. and Avista Energy arrived at a settlement in principle that would resolve this matter which obviates the need for further litigation. The 2001 bankruptcy of PG&E resulted in a default on its payment obligations to the CalPX, and as a result, Avista Energy has not been paid for all of its sales during the Refund Period. Those funds have been held in escrow accounts pending resolution of this proceeding. The settlement would return $15 million of Avista Energy's receivable to Avista Energy, with the balance of the Avista Energy receivable flowing to the purchasers associated with the hourly transactions at issue. There is no admission of wrongdoing on the part of the settling parties, and thus it is further agreed that no part of the refund payment by Avista Energy constitutes a fine or a penalty. The settlement resolves all claims for alleged overcharges during the Summer and Refund Periods in the California Refund Proceeding, and in the Pacific Northwest Refund Proceeding, for sales made to CERS, as discussed below. The settlement also includes settlement of the Federal Energy Regulatory Commission Inquiry, the Pacific Northwest Refund Proceeding, and the California Attorney General Complaint (the "Lockyer Complaint").

The settlement is subject to approval by the FERC. The Company filed the settlement at the FERC for its approval on March 7, 2014. The Company does not expect that this matter will have a material adverse effect on its financial condition, results of operations or cash flows.

Pacific Northwest Refund Proceeding

In July 2001, the FERC initiated a preliminary evidentiary hearing to develop a factual record as to whether prices for spot market sales of wholesale energy in the Pacific Northwest between December 25, 2000 and June 20, 2001 were just and reasonable. In June 2003, the FERC terminated the Pacific Northwest refund proceedings, after finding that the equities do not justify the imposition of refunds. In August 2007, the Ninth Circuit found that the FERC, in denying the request for refunds, had failed to take into account new evidence of market manipulation in the California energy market and its potential ties to the Pacific Northwest energy market and that such failure was arbitrary and capricious and, accordingly, remanded the case to the FERC, stating that the FERC's findings must be reevaluated in light of the evidence. The Ninth Circuit expressly declined to direct the FERC to grant refunds. On October 3, 2011, the FERC issued an Order on Remand, finding that, in light of the Ninth Circuit's remand order, additional procedures are needed to address possible unlawful activity that may have influenced prices in the Pacific Northwest spot market during the period from

December 25, 2000 through June 20, 2001. The Order on Remand established an evidentiary, trial-type hearing before an ALJ, and reopened the record to permit parties to present evidence of unlawful market activity. The Order on Remand stated that parties seeking refunds must submit evidence demonstrating that specific unlawful market activity occurred, and must demonstrate that such activity directly affected negotiations with respect to the specific contract rate about which they complain. Simply alleging a general link between the dysfunctional spot market in California and the Pacific Northwest spot market will not be sufficient to establish a causal connection between a particular seller's alleged unlawful activities and the specific contract negotiations at issue.

On July 11, 2012, Avista Energy and Avista Corp. filed settlements of all issues in this docket with regard to the claims made by the City of Tacoma, which the FERC approved. The two remaining direct claimants against Avista Corp. and Avista Energy in this proceeding are the City of Seattle, Washington (Seattle), and the California AG (on behalf of CERS).

On April 5, 2013, the FERC issued an Order on Rehearing expanding the temporal scope of the proceeding to permit parties to submit evidence on transactions during the period from January 1, 2000 through and including June 20, 2001.

On April 11, 2013, the California Parties filed a petition for review of the October 3, 2011 Order on Remand, and the April 5, 2013 Order on Rehearing, in the Ninth Circuit. Seattle filed a petition for review of the same orders on April 26, 2013. On May 22, 2013, the Ninth Circuit issued an order consolidating the California Parties' and Seattle's petitions for review with respect to the Order on Remand and the Order on Rehearing.

The hearing before an ALJ began on August 27, 2013, and briefing is now concluded. The ALJ's initial decision is anticipated on or before March 18, 2014.

As discussed in "California Refund Proceeding" above, in November 2013, Avista Corp. and Avista Energy arrived at a settlement in principle that would resolve these matters with regard to the CERS claims. The settlement is subject to approval by the FERC. The Company filed the settlement at the FERC for its approval on March 7, 2014. Seattle continues to pursue claims against both Avista Corp. and Avista Energy, and if, refunds are ordered by the FERC with regard to any particular contract with Seattle, Avista Corp. and Avista Energy could be liable to make payments. The Company cannot predict the outcome of this proceeding or the amount of any refunds that Avista Corp. or Avista Energy could be ordered to make. Therefore, the Company cannot predict the potential impact the outcome of this matter could ultimately have on the Company's results of operations, financial condition or cash flows.

California Attorney General Complaint (the "Lockyer Complaint")

In May 2002, the FERC conditionally dismissed a complaint filed in March 2002 by the California AG that alleged violations of the FPA by the FERC and all sellers (including Avista Corp. and its subsidiaries) of electric power and energy into California. The complaint alleged that the FERC's adoption and implementation of market-based rate authority was flawed and, as a result, individual sellers should refund the difference between the rate charged and a just and reasonable rate. In May 2002, the FERC issued an order dismissing the complaint. In September 2004, the Ninth Circuit upheld the FERC's market-based rate authority, but held that the FERC erred in ruling that it lacked authority to order refunds for violations of its reporting requirement. The Court remanded the case for further proceedings, which ultimately resulted in summary disposition at the FERC in favor of Avista Corp. and Avista Energy. The proceeding is now before the Ninth Circuit.

As discussed in "California Refund Proceeding" above, in November 2013, Avista Corp. and Avista Energy arrived at a settlement in principle that would resolve these matters and obviate the need for further litigation. The settlement is subject to approval by the FERC. The Company filed the settlement at the FERC for its approval on March 7, 2014. The Company does not expect that this matter will have a material adverse effect on its financial condition, results of operations or cash flows.

Colstrip Generating Project - Complaint Alleging Water Pollution

In March 2007, two families that own property near the holding ponds from Units 3 & 4 of the Colstrip Generating Project (Colstrip) filed a complaint against the owners of Colstrip and Hydrometrics, Inc. in Montana District Court. Avista Corp. owns a 15 percent interest in Units 3 & 4 of Colstrip. The plaintiffs alleged that the holding ponds and remediation activities adversely impacted their property. They alleged contamination, decrease in water tables, reduced flow of streams on their property and other similar impacts to their property. They also sought punitive damages, attorneys' fees, an order by the court to remove certain ponds, and the forfeiture of profits earned from the generation of Colstrip. In September 2010, the owners of Colstrip filed a motion with the court to enforce a settlement agreement that would resolve all issues between the parties. In October 2011 the court issued an order which enforced the settlement agreement. All subsequent appeals by the plaintiffs of the court's decision were denied and in 2013 a motion to dismiss the case was approved by the court. Under the settlement, Avista Corp.'s portion of payment (which was accrued in 2010) to the plaintiffs was not material to its financial condition, results of operations or cash flows.

Sierra Club and Montana Environmental Information Center Complaint Against the Owners of Colstrip

On March 6, 2013, the Sierra Club and Montana Environmental Information Center (MEIC) (collectively "Plaintiffs"), filed a Complaint (Complaint) in the United States District Court for the District of Montana, Billings Division, against the owners of the Colstrip Generating Project (Colstrip). Avista Corp. owns a 15 percent interest in Units 3 & 4 of Colstrip. The other Colstrip co-owners are PPL Montana, Puget Sound Energy, Portland General Electric Company, NorthWestern Energy and PacifiCorp. The Complaint alleges certain violations of the Clean Air Act, including the New Source Review, Title V and opacity requirements. The Plaintiffs request that the Court grant injunctive and declaratory relief, impose civil penalties, require a beneficial environmental project in the areas affected by the alleged air pollution and require payment of Plaintiffs' costs of litigation and attorney fees.

On May 3, 2013, the Colstrip owners and operator filed a partial motion to dismiss, seeking dismissal of 36 of the 39 claims. The Plaintiffs filed their opposition on May 31, 2013, and the owners and operator filed their reply on June 21, 2013. On July 17, 2013, the Court held a preliminary pretrial conference, and on July 18, 2013, the Court issued an Order establishing a procedural schedule and deadlines.

On September 12, 2013, the Plaintiffs filed Plaintiffs' First Motion for Partial Summary Judgment on the Applicable Method for Calculating Emission Increases from Modifications Made to the Colstrip Power Plant. The Colstrip Owners and Operator Response filed their reply on November 15, 2013.

On September 27, 2013, the Plaintiffs filed an Amended Complaint. The Amended Complaint withdrew from the original Complaint fifteen claims related to seven pre-January 1, 2001 Colstrip maintenance projects, upgrade projects and work projects and claims alleging violations of Title V and opacity requirements. The Amended Complaint alleges certain violations of the Clean Air Act and the New Source Review and adds claims with respect to post-January 1, 2001 Colstrip projects. The Plaintiffs request that the Court grant injunctive and declaratory relief, order remediation of alleged environmental damage, impose civil penalties, require a beneficial environmental project in the areas affected by the alleged air pollution and require payment of Plaintiffs' costs of litigation and attorney fees.

On October 11, 2013, the Colstrip owners and operator filed a motion to dismiss, seeking dismissal of all of Plaintiffs' claims contained in the Amended Complaint. Due to the preliminary nature of the lawsuit, Avista Corporation cannot, at this time, predict the outcome of the matter.

Harbor Oil Inc. Site

Avista Corp. used Harbor Oil Inc. (Harbor Oil) for the recycling of waste oil and non-PCB transformer oil in the late 1980s and early 1990s. In June 2005, the Environmental Protection Agency (EPA) Region 10 provided notification to Avista Corp. and several other parties, as customers of Harbor Oil, that the EPA had determined that hazardous substances were released at the Harbor Oil site in Portland, Oregon and that Avista Corp. and several other parties may be liable for investigation and cleanup of the site under the Comprehensive Environmental Response, Compensation, and Liability Act, commonly referred to as the federal "Superfund" law, which provides for joint and several liability. Six potentially responsible parties, including Avista Corp., signed an Administrative Order on Consent with the EPA on May 31, 2007 to conduct a remedial investigation and feasibility study (RI/FS). Based on the RI/FS submitted to the EPA, the EPA issued a Record of Decision (ROD) which proposes the "No Action Alternative" for the site. Based on the review of its records related to Harbor Oil, the Company does not believe it is a significant contributor to this potential environmental contamination based on the small volume of waste oil it delivered to the Harbor Oil site. As such, and in light of the EPA's ROD, the Company does not expect that this matter will have a material effect on its financial condition, results of operations or cash flows. The Company has expensed its share of the RI/FS ($0.5 million) for this matter.

Spokane River Licensing

The Company owns and operates six hydroelectric plants on the Spokane River. Five of these (Long Lake, Nine Mile, Upper Falls, Monroe Street, and Post Falls) are regulated under one 50-year FERC license issued in June 2009 and are referred to as the Spokane River Project. The sixth, Little Falls, is operated under separate Congressional authority and is not licensed by the FERC. The license incorporated the 4(e) conditions that were included in the December 2008 Settlement Agreement with the United States Department of Interior and the Coeur d'Alene Tribe, as well as the mandatory conditions that were agreed to in the Idaho 401 Water Quality Certifications and in the amended Washington 401 Water Quality Certification.

As part of the Settlement Agreement with the Washington Department of Ecology (Ecology), the Company has participated in the Total Maximum Daily Load (TMDL) process for the Spokane River and Lake Spokane, the reservoir created by Long Lake Dam. On May 20, 2010, the EPA approved the TMDL and on May 27, 2010, Ecology filed an amended 401 Water Quality Certification with the FERC for inclusion into the license. The amended 401 Water Quality Certification includes the Company's level of responsibility, as defined in the TMDL, for low dissolved oxygen levels in Lake Spokane. The Company submitted a draft Water Quality Attainment Plan for Dissolved Oxygen to Ecology in May 2012 and this was approved by Ecology in September 2012. This plan was subsequently approved by the FERC. The Company began implementing this plan in 2013, and management believes costs will not be material. On July 16, 2010, the City of Post Falls and the Hayden Area Regional Sewer Board filed an appeal with the United States District Court for the District of Idaho with respect to the EPA's approval of the TMDL. The Company, the City of Coeur d'Alene, Kaiser Aluminum and the Spokane River Keeper subsequently moved to intervene in the appeal. In September 2011, the EPA issued a stay to the litigation that will be in effect until either the permits are issued and all appeals and challenges are complete or the court lifts the stay. The stay is still in effect.

During 2013, through a collaborative process with key stakeholders, a decision was reached to not move forward with a specific capital project to add oxygen to Lake Spokane. At the time of such decision, the Company had expended $1.3 million on the discontinued project. On September 26, 2013 and October 23, 2013, the UTC and IPUC, respectively, issued Orders approving the Company's petition for an accounting order authorizing deferral of costs related to the discontinued project. The Washington portion of the project costs were $0.9 million and this amount has been recorded as a regulatory asset until the next general rate case. The Idaho portion of the costs of $0.5 million was recorded as a regulatory asset during the fourth quarter of 2013 and will be included in the next general rate case. The Company will address the prudence and recovery of these costs in the next Washington and Idaho general rate cases, expected to be filed in 2014.

The UTC and IPUC approved the recovery of licensing costs through the general rate case settlements in 2009. The Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to implementing the license for the Spokane River Project.

Cabinet Gorge Total Dissolved Gas Abatement Plan

Dissolved atmospheric gas levels in the Clark Fork River exceed state of Idaho and federal water quality standards downstream of the Cabinet Gorge Hydroelectric Generating Project (Cabinet Gorge) during periods when excess river flows must be diverted over the spillway. Under the terms of the Clark Fork Settlement Agreement as incorporated in Avista Corp.'s FERC license for the Clark Fork Project, Avista Corp. has worked in consultation with agencies, tribes and other stakeholders to address this issue. In the second quarter of 2011, the Company completed preliminary feasibility assessments for several alternative abatement measures. In 2012, Avista Corp., with the approval of the Clark Fork Management Committee (created under the Clark Fork Settlement Agreement), moved forward to test one of the alternatives by constructing a spill crest modification on a single spill gate. Based on testing in 2013, the modification appears to provide significant Total Dissolved Gas reduction. Further evaluation and design improvements are underway prior to applying this approach to other spill gates. The Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to this issue.

Fish Passage at Cabinet Gorge and Noxon Rapids

In 1999, the USFWS listed bull trout as threatened under the Endangered Species Act. The Clark Fork Settlement Agreement describes programs intended to help restore bull trout populations in the project area. Using the concept of adaptive management and working closely with the USFWS, the Company evaluated the feasibility of fish passage at Cabinet Gorge and Noxon Rapids. The results of these studies led, in part, to the decision to move forward with development of permanent facilities, among other bull trout enhancement efforts. Fishway designs for Cabinet Gorge are still being finalized. Construction cost estimates and schedules will be developed after several remaining issues are resolved, related to Montana's approval of fish transport from Idaho and expected minimum discharge requirements. Fishway design for Noxon Rapids has also been initiated, and is still in early stages.

In January 2010, the USFWS revised its 2005 designation of critical habitat for the bull trout to include the lower Clark Fork River as critical habitat. The Company believes its ongoing efforts through the Clark Fork Settlement Agreement continue to effectively address issues related to bull trout. The Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to fish passage at Cabinet Gorge and Noxon Rapids.

Aluminum Recycling Site

In October 2009, the Company (through its subsidiary Pentzer Venture Holdings II, Inc. (Pentzer)) received notice from Ecology proposing to find Pentzer liable for a release of hazardous substances under the Model Toxics Control Act (MTCA), under Washington state law. Pentzer owns property that adjoins land owned by the Union Pacific Railroad (UPR). UPR leased their property to operators of a facility designated by Ecology as "Aluminum Recycling - Trentwood." Operators of the UPR property maintained piles of aluminum dross, which designate as a state-only dangerous waste in Washington State. In the course of its business, the operators placed a portion of the aluminum dross pile on the property owned by Pentzer. During the second quarter of 2013, the Company completed an agreement with UPR which resolves all liability related to the MTCA action. Through Pentzer Corporation, a wholly-owned subsidiary of the Company, the Company made a one-time payment of $0.1 million and UPR has taken full responsibility for the cleanup activities at the site. Based on information currently known to the Company's management, the Company believes any potential liability related to the site has been resolved, and does not expect this issue will have a material effect on its financial condition, results of operations or cash flows.

Collective Bargaining Agreements

The Company's collective bargaining agreement with the International Brotherhood of Electrical Workers represents approximately 45 percent of all of Avista Corp.'s employees. The agreement with the local union in Washington and Idaho representing the majority (approximately 90 percent) of the bargaining unit employees expired in March 2014. Two local agreements in Oregon, which cover approximately 50 employees, expired in March 2014. Negotiations are currently ongoing for these labor agreements.

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 analyses 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. For matters that affect Avista Corp.'s operations, the Company seeks, to the extent appropriate, recovery of incurred costs through the ratemaking process.

The Company has potential liabilities under the Endangered Species Act for species of fish 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 this issue.

Under the federal licenses for its hydroelectric projects, the Company is obligated to protect its property rights, including water rights. The state of Montana is examining the status of all water right claims within state boundaries. 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. In addition, the state of Washington has indicated an interest in initiating adjudication for the Spokane River basin in the next several years. The Company is and will continue to be a participant in these 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.

NOTE 18. INFORMATION SERVICES CONTRACTS

The Company has information services contracts that expire at various times through 2017. The largest of these contracts provides for increases due to changes in the cost of living index and further provides flexibility in the annual obligation from year-to-year. Total payments under these contracts were as follows for the years ended December 31 (dollars in thousands):

	2013	2012
Information service contract payments	$ 12,647	$ 13,221

The majority of the costs are included in other operating expenses in the Statements of Income. The following table details minimum future contractual commitments for these agreements (dollars in thousands):

	2014	2015	2016	2017	2018	Thereafter	Total
Contractual obligations	$ 8,350	$ 7,384	$ 7,446	$ 7,508	$ —	$ —	$ 30,688

NOTE 19. REGULATORY MATTERS

Power Cost Deferrals and Recovery Mechanisms

Deferred power supply costs are recorded as a deferred charge on the Balance Sheets for future prudence review and recovery 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 and availability of hydroelectric generation,
- the level and availability of thermal generation (including changes in fuel prices),
- the net value from optimization activities related to the Company's generating resources, and
- retail loads.

In Washington, the Energy Recovery Mechanism (ERM) allows Avista Corp. to periodically increase or decrease electric rates with UTC 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 the margin on wholesale sales and sales of fuel, and the amount included in base retail rates for Washington customers. Total net deferred power costs under the ERM were a liability of $17.9 million as of December 31, 2013, and these deferred power cost balances represent amounts due to customers. As part of the approved Washington general rate case settlement in December 2012, during 2013 a one-year credit designed to return to customers $4.4 million from the existing ERM deferral balance reduced the net average electric rate increase impact to customers in 2013. Additionally, during 2014 a one-year credit up to $9.0 million will be returned to electric customers from the ERM deferral balance, so the net average electric rate increase impact to customers effective January 1, 2014 was also be reduced. The credits to customers from the ERM balances do not impact the Company's net income.

Under the ERM, the Company 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 currently $4.0 million. The Company will incur the cost of, or receive the benefit from, 100 percent of this initial power supply cost variance. The Company shares annual power supply cost variances between $4.0 million and $10.0 million with customers. There is a 50 percent customers/50 percent Company sharing ratio when actual power supply expenses are higher (surcharge to customers) than the amount included in base retail rates within this band. There is a 75 percent customers/25 percent Company sharing ratio when actual power supply expenses are lower (rebate to customers) than the amount included in base retail rates within this band. To the extent that the annual power supply cost variance from the amount included in base rates exceeds $10.0 million, there is a 90 percent customers/10 percent Company share ratio of the cost variance.

The following is a summary of the ERM:

Annual Power Supply Cost Variability	Deferred for Future Surcharge or Rebate to Customers	Expense or Benefit
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%

As part of the April 2012 Washington general rate case filing, the Company proposed modifications to the ERM deadband and other sharing bands. The proposed modifications were not agreed to as part of the settlement agreement, and the ERM continued unchanged. However, the trigger point at which rates will change under the ERM was modified to be $30 million rather than the previous 10 percent of base revenues (approximately $45 million) under the mechanism.

Avista Corp. has a Power Cost Adjustment (PCA) mechanism in Idaho that allows it to modify electric rates on October 1 of each year with Idaho Public Utilities Commission (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. These annual 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 a regulatory asset of $5.1 million as of December 31, 2013 compared to a regulatory liability of $5.1 million as of December 31, 2012.

Natural Gas Cost Deferrals and Recovery Mechanisms

Avista Corp. files a purchased gas cost adjustment (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. These annual PGA filings in Washington and Idaho provide for the deferral, and recovery or refund, of 100 percent of the difference between actual and estimated commodity and pipeline transportation costs, subject to applicable regulatory review. The annual PGA filing in Oregon provides for deferral, and recovery or refund, of 100 percent of the difference between actual and estimated pipeline transportation costs and commodity costs that are fixed through hedge transactions. Commodity costs that are not hedged for Oregon customers are subject to a sharing mechanism whereby Avista Corp. defers, and recovers or refunds, 90 percent of the difference between these actual and estimated costs. Total net deferred natural gas costs to be refunded to customers were a liability of $12.1 million as of December 31, 2013 compared to a liability of $6.9 million as of December 31, 2012.

Washington General Rate Cases

In December 2011, the UTC approved a settlement agreement in the Company's electric and natural gas general rate cases filed in May 2011. The settlement agreement provided for the deferral of certain generation plant maintenance costs. For 2011 and 2012 the Company compared actual non-fuel maintenance expenses for the Coyote Springs 2 and Colstrip plants with the amount of baseline maintenance expenses used to establish base retail rates, and deferred the difference. This deferral occurred each year, with no carrying charge, with deferred costs to be amortized over a four-year period, beginning the year following the period costs are deferred. Total net deferred costs under this mechanism in Washington were a regulatory asset of $3.1 million as of December 31, 2013 compared to a regulatory asset of $4.0 million as of December 31, 2012. As part of the settlement agreement relating to the Company's latest general rate case approved in December 2012, the parties agreed to terminate the maintenance cost deferral mechanism on December 31, 2012, with the four-year amortization of the 2011 and 2012 deferrals to conclude in 2015 and 2016, respectively.

In December 2012, the UTC approved a settlement agreement in the Company's electric and natural gas general rate cases filed in April 2012. The settlement, effective January 1, 2013, provided that base rates for Washington electric customers increase by an overall 3.0 percent (designed to increase annual revenues by $13.6 million), and base rates for Washington natural gas customers increased by an overall 3.6 percent (designed to increase annual revenues by $5.3 million). Under the settlement, there was a one-year credit designed to return $4.4 million to electric customers from the existing ERM deferral balance so the net average electric rate increase impact to the Company's customers in 2013 was 2.0 percent. The credit to customers from the ERM balance did not impact the Company's earnings.

The approved settlement also provided that, effective January 1, 2014, the Company increased base rates for Washington electric customers by an overall 3.0 percent (designed to increase annual revenues by $14.0 million), and for Washington natural gas customers by an overall 0.9 percent (designed to increase annual revenues by $1.4 million). The settlement provides for a one-year credit up to $9.0 million to electric customers from the ERM deferral balance, so the net average electric rate increase to customers effective January 1, 2014 was 2.0 percent. The credit to customers from the ERM balance will not impact the Company's earnings. The ERM balance as of December 31, 2013 was a liability of $17.9 million.

The settlement agreement provides for an authorized return on equity of 9.8 percent and an equity ratio of 47.0 percent, resulting in an overall rate of return on rate base of 7.64 percent.

The December 2012 UTC Order approving the settlement agreement included certain conditions.

(1) The new retail rates to become effective January 1, 2014 will be temporary rates, and on January 1, 2015 electric and natural gas base rates will revert back to 2013 levels absent any intervening action from the UTC. The original settlement agreement has a provision that the Company will not file a general rate case in Washington seeking new rates to take effect before January 1, 2015.

(2) In its Order, the UTC found that much of the approved base rate increases are justified by the planned capital expenditures necessary to upgrade and maintain the Company's utility facilities. If these capital projects are not completed to a level that was contemplated in the settlement agreement, this could result in base rates which are considered too high by the UTC. Avista Corp. is required to file capital expenditure progress reports with the UTC on a periodic basis so that the UTC can

monitor the capital expenditures and ensure they are in line with those contemplated in the settlement agreement. The Company expects total utility capital expenditures to be above the level contemplated in the settlement agreement.

On February 4, 2014 the Company filed electric and natural gas general rates cases with the UTC. The Company has requested an overall increase in base electric rates of 3.8 percent (designed to increase annual electric revenues by $18.2 million) and an overall increase in base natural gas rates of 8.1 percent (designed to increase annual natural gas revenues by $12.1 million). The requests are based on a proposed overall rate of return of 7.71 percent, with a common equity ratio of 49.0 percent and a 10.1 percent return on equity.

Avista Corp. has also proposed a rebate beginning January 1, 2015, related to its sale of renewable energy credits (REC), that would reduce customers' monthly electric bills by 1.1 percent. The rebate associated with the sale of RECs is in response to the UTC Order approving the Company's previous general rate case settlement in December 2012. This proposed REC rebate would commence simultaneously with the expiration of two rebates that, together, are currently reducing customers' monthly electric bills by 2.8 percent. The net effect, commencing January 1, 2015, of the proposed new 1.1 percent rebate and the expiration of the current 2.8 percent rebate would be an increase in monthly electric bills of approximately 1.7 percent from 2014 levels. These rebates do not increase or decrease Avista Corp.'s earnings.

The combination of the 3.8 percent requested increase in base electric rates and the effective 1.7 percent increase attributable to the rebates would be a 5.5 percent increase electric billings.

As part of the Company's electric and natural gas general rate case filings, it has requested the implementation of decoupling mechanisms which sever the link between actual volumetric sales and the recovery of the Company's fixed costs. Under the proposed decoupling mechanisms, the Company would compare actual non-power supply (electric) and non-PGA (natural gas) revenue to the allowed non-power supply and non-PGA revenue, as the case may be, and the difference would be deferred and either rebated or surcharged to customers, depending on the position of the deferral accounts, over a one-year period. The deferral balances would be reviewed annually by the UTC prior to the implementation of any annual rate adjustments under the mechanisms.

The proposed mechanisms would be subject to an annual earnings test which proposes that if the Company's actual annual "Commission-basis" rate of return exceeds the most recently authorized Commission-basis rate of return for the Company's Washington electric and natural gas operations, the amount of a proposed surcharge is reduced or eliminated to reduce the rate of return to the Commission-authorized level. In addition, the mechanisms would be subject to an annual rate increase limitation which would prevent the amount of the incremental proposed rate adjustments under the mechanisms from exceeding a 3 percent rate increase for each of electric and natural gas operations.

The UTC has up to 11 months to review the filings and issue a decision.

Idaho General Rate Cases

In September 2011, the IPUC approved a settlement agreement in the Company's general rate case filed in July 2011. The settlement agreement provides for the deferral of certain generation plant operation and maintenance costs. In order to address the variability in year-to-year operation and maintenance costs, beginning in 2011, the Company is deferring certain changes in operation and maintenance costs related to the Coyote Spring 2 natural gas-fired generation plant and its 15 percent ownership interest in Units 3 & 4 of the Colstrip generation plant. The Company compares actual, non-fuel, operation and maintenance expenses for the Coyote Springs 2 and Colstrip plants with the amount of expenses authorized for recovery in base rates in the applicable deferral year, and defers the difference from that currently authorized. The deferral occurs annually, with no carrying charge, with deferred costs being amortized over a three-year period, beginning in the year following the period costs are deferred. The amount of expense to be requested for recovery in future general rate cases will be the actual operation and maintenance expense recorded in the test period, less any amount deferred during the test period, plus the amortization of previously deferred costs. Total net deferred costs under this mechanism in Idaho were regulatory assets of $2.8 million as of December 31, 2013 and $2.3 million as of December 31, 2012.

In March 2013, the IPUC approved a settlement agreement in the Company's electric and natural gas general rate cases filed in October 2012. As agreed to in the settlement, new rates were implemented in two phases: April 1, 2013 and October 1, 2013. Effective April 1, 2013, base rates increased for the Company's Idaho natural gas customers by an overall 4.9 percent (designed to increase annual revenues by $3.1 million). There was no change in base electric rates on April 1, 2013. However, the settlement agreement provided for the recovery of the costs of the Palouse Wind Project, subject to the 90 percent customers/10 percent Company sharing ratio, through the PCA mechanism until these costs are reflected in base retail rates in the next general rate case.

The settlement also provided that, effective October 1, 2013, base rates increased for Idaho natural gas customers by an overall 2.0 percent (designed to increase annual revenues by $1.3 million). A credit resulting from deferred natural gas costs of $1.6 million is being returned to the Company's Idaho natural gas customers from October 1, 2013 through December 31, 2014, so the net annual average natural gas rate increase to natural gas customers effective October 1, 2013 was 0.3 percent.

Further, the settlement provided that, effective October 1, 2013, base rates increased for Idaho electric customers by an overall 3.1 percent (designed to increase annual revenues by $7.8 million). A $3.9 million credit resulting from a payment to be made to Avista Corp. by the Bonneville Power Administration relating to its prior use of Avista Corp.'s transmission system is being returned to Idaho electric customers from October 1, 2013 through December 31, 2014, so the net annual average electric rate increase to electric customers effective October 1, 2013 was 1.9 percent.

The $1.6 million credit to Idaho natural gas customers and the $3.9 million credit to Idaho electric customers do not impact the Company's net income.

The settlement agreement allows the Company to file a general rate case in Idaho in 2014; however, new rates resulting from the filing would not take effect prior to January 1, 2015.

The settlement agreement provides for an authorized return on equity of 9.8 percent and an equity ratio of 50.0 percent.

The settlement also includes an after-the-fact earnings test for 2013 and 2014, such that if Avista Corp., on a consolidated basis for electric and natural gas operations in Idaho, earns more than a 9.8 percent return on equity, Avista Corp. will refund to customers 50 percent of any earnings above the 9.8 percent. In 2013, the Company's returns exceeded this level and the Company will refund $2.0 million to Idaho electric customers and $0.4 million to Idaho natural gas customers. The period over which these amounts will be returned to customers has not yet been determined by the IPUC.

Oregon General Rate Case

On January 21, 2014, the Public Utility Commission of Oregon (OPUC) approved a settlement agreement to the Company's natural gas general rate case (originally filed in August 2013). As agreed to in the settlement, new rates will be implemented in two phases: February 1, 2014 and November 1, 2014. Effective February 1, 2014, rates increased for Oregon natural gas customers on a billed basis by an overall 4.4 percent (designed to increase annual revenues by $4.3 million). Effective November 1, 2014, rates for Oregon natural gas customers will increase on a billed basis by an overall 1.55 percent (designed to increase annual revenues by $1.4 million).

The billed rate increase on November 1, 2014 could vary slightly from that noted above as it is dependent upon actual costs incurred through September 30, 2014 related to the Company's customer information system upgrade and the actual costs incurred through June 30, 2014 related to the Company's Aldyl A distribution pipeline replacement program. The estimated capital expenditures included in the general rate case settlement are $6.5 million and $2.0 million, respectively, for the two projects. If the actual costs incurred on the above projects are greater than the amounts contemplated in the general rate case settlement, the additional costs could be approved for recovery, subject to a prudence review.

The approved settlement agreement provides for an overall authorized rate of return of 7.47 percent, with a common equity ratio of 48 percent and a 9.65 percent return on equity.

Bonneville Power Administration Reimbursement and Reardan Wind Generation Project

On May 9, 2013, the UTC approved the Company's Petition for an order authorizing certain accounting and ratemaking treatment related to two issues. The first issue relates to transmission revenues associated with a settlement between Avista Corp. and the Bonneville Power Administration (BPA), whereby the BPA reimbursed the Company $11.7 million for Bonneville's past use of Avista Corp.'s transmission system. The second issue relates to $4.3 million of costs the Company incurred over the past several years for the development of a wind generation project site near Reardan, Washington, which has been terminated. The UTC authorized the Company to retain $7.6 million of the BPA settlement payment, representing the entire portion of the settlement allocable to the Washington business. However, this amount was deemed to first reimburse the Company for the $2.5 million of Reardan project costs that are allocable to the Washington business, leaving $5.1 million to be retained for the benefit of shareholders.

The BPA agreed to pay $0.3 million monthly ($3.2 million annually) for the future use of Avista Corp.'s transmission system. The Company is separately tracking and deferring for the customers' benefit, the Washington portion of these revenue payments in 2013 and 2014 ($2.1 million annually). The Company implemented a one-year $4.2 million rate decrease for customers effective January 1, 2014 to partially offset the electric general rate increase effective January 1, 2014. To the extent actual revenues from the BPA in 2013 and 2014 differ from those refunded to customers in 2014, the difference will be added to or subtracted from the ERM balance. In Idaho, under the terms of the approved rate case settlement, 90 percent of the portion of the BPA settlement allocable to the Idaho business ($4.1 million) is being credited back to customers over 15 months, beginning October 2013, and the Company is amortizing the Idaho portion of Reardan costs ($1.7 million) over a two-year period, beginning April 2013.

NOTE 20. SUPPLEMENTAL CASH FLOW INFORMATION (in thousands)

	2013	2012
Cash paid for interest	$70,444	$68,508
Cash paid for income taxes	$42,497	$6,631

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year	134,046	(5,770,872)		
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	(290,263)			
3	Preceding Quarter/Year to Date Changes in Fair Value	323,478	(1,096,549)		
4	Total (lines 2 and 3)	33,215	(1,096,549)		
5	Balance of Account 219 at End of Preceding Quarter/Year	167,261	(6,867,421)		
6	Balance of Account 219 at Beginning of Current Year	167,261	(6,867,421)		
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	(12,411)			
8	Current Quarter/Year to Date Changes in Fair Value	(1,740,705)	2,633,346		
9	Total (lines 7 and 8)	(1,753,116)	2,633,346		
10	Balance of Account 219 at End of Current Quarter/Year	(1,585,855)	(4,234,075)		

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2014	Year/Period of Report End of 2013/Q4

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1			(5,636,826)		
2			(290,263)		
3			(773,071)		
4			(1,063,334)	78,210,066	77,146,732
5			(6,700,160)		
6			(6,700,160)		
7			(12,411)		
8			892,641		
9			880,230	111,076,833	111,957,063
10			(5,819,930)		

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

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

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

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	4,268,598,886	3,165,732,548
4	Property Under Capital Leases	6,442,349	
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	4,275,041,235	3,165,732,548
9	Leased to Others		
10	Held for Future Use	4,964,376	4,773,791
11	Construction Work in Progress	157,258,690	97,884,894
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	4,437,264,301	3,268,391,233
14	Accum Prov for Depr, Amort, & Depl	1,491,212,830	1,136,326,135
15	Net Utility Plant (13 less 14)	2,946,051,471	2,132,065,098
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	1,454,623,625	1,123,890,020
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	36,589,205	12,436,115
22	Total In Service (18 thru 21)	1,491,212,830	1,136,326,135
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	1,491,212,830	1,136,326,135

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2014	Year/Period of Report End of 2013/Q4

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
837,923,760				264,942,578	3
858,865				5,583,484	4
					5
					6
					7
838,782,625				270,526,062	8
					9
190,585					10
5,077,638				54,296,158	11
					12
844,050,848				324,822,220	13
283,173,038				71,713,657	14
560,877,810				253,108,563	15
					16
					17
281,451,295				49,282,310	18
					19
					20
1,721,743				22,431,347	21
283,173,038				71,713,657	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
283,173,038				71,713,657	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

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

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of 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)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents	44,651,922	
4	(303) Miscellaneous Intangible Plant	5,009,716	1,135,323
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	49,661,638	1,135,323
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	3,488,301	1,508
9	(311) Structures and Improvements	126,221,007	1,327,443
10	(312) Boiler Plant Equipment	164,036,458	3,335,839
11	(313) Engines and Engine-Driven Generators	6,770	
12	(314) Turbogenerator Units	52,327,599	1,268,325
13	(315) Accessory Electric Equipment	26,162,267	550,772
14	(316) Misc. Power Plant Equipment	15,941,361	419,776
15	(317) Asset Retirement Costs for Steam Production	585,275	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	388,769,038	6,903,663
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	57,951,081	329,776
28	(331) Structures and Improvements	44,268,474	2,263,306
29	(332) Reservoirs, Dams, and Waterways	124,134,363	7,387,442
30	(333) Water Wheels, Turbines, and Generators	163,044,481	183
31	(334) Accessory Electric Equipment	34,012,512	3,658,355
32	(335) Misc. Power PLant Equipment	8,127,342	1,184,366
33	(336) Roads, Railroads, and Bridges	2,020,756	320,283
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	433,559,009	15,143,711
36	D. Other Production Plant		
37	(340) Land and Land Rights	905,167	
38	(341) Structures and Improvements	16,581,560	208,590
39	(342) Fuel Holders, Products, and Accessories	21,168,978	5,068
40	(343) Prime Movers	23,688,559	220,911
41	(344) Generators	198,862,632	6,395,594
42	(345) Accessory Electric Equipment	17,111,998	4,546,415
43	(346) Misc. Power Plant Equipment	1,719,527	131,670
44	(347) Asset Retirement Costs for Other Production	351,683	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	280,390,104	11,508,248
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,102,718,151	33,555,622

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

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
			44,651,922		3
131,806			6,013,233		4
131,806			50,665,155		5
					6
					7
			3,489,809		8
120,395			127,428,055		9
1,079,370			166,292,927		10
			6,770		11
618,104			52,977,820		12
147,793			26,565,246		13
			16,361,137		14
			585,275		15
1,965,662			393,707,039		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			58,280,857		27
150,786			46,380,994		28
83,371			131,438,434		29
69,886			162,974,778		30
374,883			37,295,984		31
91,606			9,220,102		32
			2,341,039		33
					34
770,532			447,932,188		35
					36
			905,167		37
23,474			16,766,676		38
			21,174,046		39
			23,909,470		40
5,985			205,252,241		41
1,313,870			20,344,543		42
356,713			1,494,484		43
			351,683		44
1,700,042			290,198,310		45
4,436,236			1,131,837,537		46

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	18,731,287	446,520
49	(352) Structures and Improvements	17,104,372	2,207,754
50	(353) Station Equipment	213,222,173	8,863,916
51	(354) Towers and Fixtures	17,122,931	1,625
52	(355) Poles and Fixtures	154,797,876	9,863,180
53	(356) Overhead Conductors and Devices	116,767,616	4,077,984
54	(357) Underground Conduit	2,605,488	232,902
55	(358) Underground Conductors and Devices	2,330,072	1,288
56	(359) Roads and Trails	1,872,246	77,613
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	544,554,061	25,772,782
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	6,735,049	283,713
61	(361) Structures and Improvements	17,970,103	315,350
62	(362) Station Equipment	111,338,207	6,244,898
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	261,335,205	20,277,906
65	(365) Overhead Conductors and Devices	173,751,442	13,888,184
66	(366) Underground Conduit	85,678,110	2,735,068
67	(367) Underground Conductors and Devices	141,648,755	9,505,246
68	(368) Line Transformers	198,972,431	10,632,331
69	(369) Services	132,648,550	4,833,670
70	(370) Meters	47,965,620	653,761
71	(371) Installations on Customer Premises		
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	36,385,470	2,811,371
74	(374) Asset Retirement Costs for Distribution Plant	129,707	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,214,558,649	72,181,498
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	385,053	13,611
87	(390) Structures and Improvements	6,229,403	576,262
88	(391) Office Furniture and Equipment	7,870,002	555,895
89	(392) Transportation Equipment	17,608,384	5,872,463
90	(393) Stores Equipment	395,329	
91	(394) Tools, Shop and Garage Equipment	3,185,939	90,909
92	(395) Laboratory Equipment	920,024	6,050
93	(396) Power Operated Equipment	36,041,674	3,747,047
94	(397) Communication Equipment	48,854,842	4,470,949
95	(398) Miscellaneous Equipment	30,511	26,614
96	SUBTOTAL (Enter Total of lines 86 thru 95)	121,521,161	15,359,800
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant		
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	121,521,161	15,359,800
100	TOTAL (Accounts 101 and 106)	3,033,013,660	148,005,025
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	3,033,013,660	148,005,025

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
			19,177,807		48
18,295			19,293,831		49
1,266,860			220,819,229		50
			17,124,556		51
816,192			163,844,864		52
637,694			120,207,906		53
			2,838,390		54
			2,331,360		55
			1,949,859		56
					57
2,739,041			567,587,802		58
					59
			7,018,762		60
82,392			18,203,061		61
1,660,668			115,922,437		62
					63
1,063,036			280,550,075		64
-310,842			187,950,468		65
-34,859			88,448,037		66
538,159			150,615,842		67
1,938,563			207,666,199		68
-91,510			137,573,730		69
661,148			47,958,233		70
					71
					72
69,403			39,127,438		73
			129,707		74
5,576,158			1,281,163,989		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			398,664		86
25,548			6,780,117		87
344,417			8,081,480		88
461,012			23,019,835		89
			395,329		90
261,880			3,014,968		91
211,128			714,946		92
632,319			39,156,402		93
466,584			52,859,207		94
8			57,117		95
2,402,896			134,478,065		96
					97
					98
2,402,896			134,478,065		99
15,286,137			3,165,732,548		100
					101
					102
					103
15,286,137			3,165,732,548		104

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2				
3				
4	Distribution Plant Land, Spokane, Washington	Oct 2008	Unknown	1,623,321
5	Distribution UG Plant Land, Spokane, Washington	Dec 2010	Unknown	212,647
6	Transmission Plant Land, Spokane, Washington	Dec 2010	Unknown	197,254
7	Transmission Plant Land, Moscow, Idaho	March 2011	Unknown	126,640
8	Distribution Plant Land, Spokane, Washington	March 2011	Unknown	540,307
9	Distribution Plant Land, Spokane, Washington	Oct 2011	Unknown	414,073
10	Transmission Plant Land, Spokane, Washington	Dec 2011	Unknown	1,143,033
11	Distribution Plant Land, Spokane, Washington	Dec 2011	Unknown	250,489
12	Other Production Plant Land, Spokane, Washington	Dec 2011	Unknown	40,896
13	Distribution Plant Land, Deary, Idaho	June 2012	Unknown	72,367
14	Transmission Plant Land, Thornton, Washington	Aug 2012	Unknown	1,383
15	Distribution Plant Land, Spokane, Washington	Oct 2012	Unknown	151,381
16				
17				
18				
19				
20				
21	Other Property:			
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			4,773,791

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Nine Mile Redevelopment	20,405,502
2	Clark Fork IMP	15,412,280
3	Spokane River Implementation	6,579,669
4	Productivity Initiative	5,767,316
5	Moscow 230kV Sub Rebuild 230kV Yard	5,731,102
6	Little Falls Powerhouse Redevelopmnt	5,209,831
7	Customer Information System (CIS) Replacement	4,511,669
8	High Voltage Protection Updgrade	1,861,206
9	Regulating Hydro	1,723,453
10	Millwood Sub - Rebuild	1,491,955
11	Line Ratings Mitigation Project	1,429,569
12	Sys Wood Substation Rebuilds	1,419,632
13	Blue Creek 115kV Rebuild	1,413,514
14	Cabinet Gorge HED U#1 Refurbishment	1,390,201
15	Post Falls S Channel Gate Replacement	1,200,680
16	Systm-Replc/Instl Capacitor Banks	1,192,965
17	Distribution Spokane North & West	1,050,091
18	Sandpoint Grid Modernization Project	1,038,751
19	Clearwater 115 kV Substation Upgrades	1,010,865
20	Minor Projects under $1,000,000	15,141,651
21		
22	Research, Development, and Demonstrating:	
23	SGDP Pullman Smart Grid Demo Proj	2,902,992
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	97,884,894

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

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

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	1,065,032,018	1,065,032,018		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	74,025,638	74,025,638		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	4,587,922	4,587,922		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	-164,900	-164,900		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	78,448,660	78,448,660		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	15,240,233	15,240,233		
13	Cost of Removal	1,889,741	1,889,741		
14	Salvage (Credit)	25,394	25,394		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	17,104,580	17,104,580		
16	Other Debit or Cr. Items (Describe, details in footnote):	-2,486,078	-2,486,078		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,123,890,020	1,123,890,020		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	277,816,759	277,816,759		
21	Nuclear Production				
22	Hydraulic Production-Conventional	123,118,375	123,118,375		
23	Hydraulic Production-Pumped Storage				
24	Other Production	82,790,065	82,790,065		
25	Transmission	189,994,238	189,994,238		
26	Distribution	394,968,478	394,968,478		
27	Regional Transmission and Market Operation	55,202,105	55,202,105		
28	General				
29	TOTAL (Enter Total of lines 20 thru 28)	1,123,890,020	1,123,890,020		

Schedule Page: 219 Line No.: 16 Column: c

Schedule Page: 219 Line No.:8 Column: c

Includes:
Adjustment to 2013 Beginning Reserve Balance of $2,760
ARO adjustment of $85,900 to 108000
Miscellaneous adjustment of $15,219 to 108000
Accretion expense of $22,019 182376 to 108000
Accumulated provision of non-recoverable plant of $-290,798 for Kettle Falls and Boulder Park

Schedule Page: 219 Line No.: 16 Column: c
Includes:
Change in Removal Work in Progress of $-2,486,078

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1				
2	Avista Capital - Common Stock	1997		216,728,833
3	Avista Capital - Equity in Earnings			-102,654,241
4	OCI Investment in Subs			167,261
5	Avista Capital - Other Changes in Net Investment			4,472,570
6				
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42	Total Cost of Account 123.1 $ 0		TOTAL	118,714,423

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
	-10,503,285	206,225,548		2
4,593,239		-98,061,002		3
	-1,753,116	-1,585,855		4
	1,180,843	5,653,413		5
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4,593,239	-11,075,558	112,232,104		42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	4,120,767	3,170,050	(1)
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	16,046,143	17,104,229	(1)
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	2,645,483	2,721,461	(1)
8	Transmission Plant (Estimated)	54,922	166,825	(1)
9	Distribution Plant (Estimated)	264,561	316,067	(1)
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	4,864,288	6,347,128	(1),(2)
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	23,875,397	26,655,710	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)			
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	27,996,164	29,825,760	

Schedule Page: 227 Line No.: 1 Column: d

(1) Electric
(2) Gas

Schedule Page: 227 Line No.: 5 Column: d

Footnote Linked. See note on 227, Row: 1, col/item:

Schedule Page: 227 Line No.: 7 Column: d

Footnote Linked. See note on 227, Row: 1, col/item:

Schedule Page: 227 Line No.: 8 Column: d

Footnote Linked. See note on 227, Row: 1, col/item:

Schedule Page: 227 Line No.: 9 Column: d

Footnote Linked. See note on 227, Row: 1, col/item:

Schedule Page: 227 Line No.: 11 Column: d

Footnote Linked. See note on 227, Row: 1, col/item:

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

Transmission Service and Generation Interconnection Study Costs

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

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
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21	**Generation Studies**				
22	AVA Noxon Upgrade	40,214	186200		
23	Palouse Wind Phase II	7,965	186200		
24	AVA Nine Mile Upgrade	3,259	186200		
25					
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Schedule Page: 231 Line No.: 22 Column: a

Total charges incurred life to date.

Schedule Page: 231 Line No.: 23 Column: a

Total charges incurred life to date.

Schedule Page: 231 Line No.: 24 Column: a

Total charges incurred life to date.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS: Written off During the Quarter /Year Account Charged (d)	CREDITS: Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Reg Asset Post Ret Liab	306,407,669		228	149,423,373	156,984,296
2	Regulatory Asset FAS109 Utility Plant	65,464,605		283	2,579,600	62,885,005
3	Regulatory Asset Lancaster Generation	3,966,667		407	1,360,000	2,606,667
4	Regulatory Asset FAS109 DSIT Non Plant	1,664,766		283	407,172	1,257,594
5	Regulatory Asset FAS109 DFIT State Tax Cr	7,464,184		283	4,282,115	3,182,069
6	Regulatory Asset FAS109 WNP3	4,916,337		283	737,482	4,178,855
7	Regulatory Asset Roseburg/Medford	265,011	8,729	407	273,740	
8	Regulatory Asset- Spokane River Relicense	622,362		407	78,736	543,626
9	Regulatory Asset- Spokane River PM&E	575,886		557	73,312	502,574
10	Regulatory Asset- Lake CDA Fund	9,437,599		407	211,065	9,226,534
11	Regulatory Asset- Lake CDA IPA Fund	2,000,000				2,000,000
12	Regulatory Asset- Spokane River TDG Idaho		468,893			468,893
13	Reg Assets- Decouplings Surcharge	7,324	242			7,566
14	Regulatory Asset- Lake CDA DEF Costs		1,310,141			1,310,141
15	Regulatory Asset BPA Residential Exchange	540,805	564,997			1,105,802
16	Regulatory Asset- CNC Transmission	483,269		407	252,637	230,632
17	DEF CS2 & COLSTRIP	6,312,395		407	499,344	5,813,051
18	LiDAR O&M REG DEF	587,258		407	519,893	67,365
19	Reardan Wind Generation		852,642			852,642
20	ID Wind Gen AFUDC	369,373		407	138,515	230,858
21	Regulatory Asset Wartsila Units	751,817		407	337,788	414,029
22	MTM St Regulatory Asset	35,081,525		244	24,252,110	10,829,415
23	MTM Lt Regulatory Asset	25,217,697		244	1,960,132	23,257,565
24	Regulatory Asset FAS143 Asset Retirement Obligation	2,398,845		230	288,613	2,110,232
25	Reg Asset AN- CDA Lake Settlement	37,627,208		407	2,226,946	35,400,262
26	Reg Asset WA-CDA Lake Settlement	1,204,270		407	152,118	1,052,152
27	Regulatory Asset Workers Comp	2,278,678	208,253			2,486,931
28	CS2 Lev Ret	909,499		407	500,500	408,999
29	Regulatory Asset ID PCA Deferral 2		8,209,413	557	3,144,178	5,065,235
30	Spokane River TDG		871,184			871,184
31	Interest Rate Swap Asset		36,525,856			36,525,856
32	DSM Asset	2,578,599	9,576,204	407	2,578,599	9,576,204
33	SWAPS ON FMBS	40,697,806		557	40,697,806	
34	Misc Reg Asset		129,705			129,705
35						
36						
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44	**TOTAL :**	559,831,454	58,726,259		236,975,774	381,581,939

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1						
2	Colstrip Common Fac.	1,110,999		406		1,110,999
3	Regulatory Asset-Mt Lease Pymt	1,352,565		540	360,684	991,881
4	Regulatory Asset-Mt Lease Pymt	2,706,480		540	676,632	2,029,848
5	Colstrip Common Fac.	2,355,642				2,355,642
6	Prepaid Airplane Lease LT	318,859		931	147,166	171,693
7	Misc DD- Airplane Lease	102,737		VAR	21,146	81,591
8	Plant Alloc of Clearing Jrl	3,584,496		VAR	520,161	3,064,335
9	Misc Error Suspense	-336,980	370,615	VAR		33,635
10	Renewable Energy-Cert Fees	164,844		557	49,594	115,250
11	Nez Perce Settlement	160,749		557	5,212	155,537
12	Long Term Note Rec Acct	5,419		143	5,419	
13	Reg Asset ID-Lake CDA	240,056		506	30,975	209,081
14	ID Panhandle Forest Use Permit	181,017			181,017	
15	Credit Union Labor and Exp	35,010	3,785	VAR		38,795
16	Outdoor Lghtng Greenbelt Pathwy	98,227			98,227	
17	Horizon Wind Interco	61,845		557	61,845	
18	KF Water Rights Supply	769		310	769	
19	Idaho Clk Fork Relic	186,950			186,950	
20	Misc Work Orders <$50,000	126,209	20,886	VAR		147,095
21	Subsidiary Billings	178,266	21,621	557		199,887
22	"Null" Projects Directly to 186	15,197		VAR	13,844	1,353
23	Regulatory Assets Consv	1,660,713	51,895	VAR		1,712,608
24	Noxon 230 KV Sub Permits		107,860			107,860
25	Optional Wind Power	-186,231	10,936	909		-175,295
26	Gas Telemetry equip		59,051			59,051
27	Misc Deffered Debits/Res Acctg	1,577,531			676,085	901,446
28						
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46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	15,701,369				13,312,292

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2		6,261,068	5,183,280
3			
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	6,261,068	5,183,280
9	Gas		
10		2,161,932	991,860
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15	2,161,932	991,860
17	Other	140,002,469	64,064,282
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	148,425,469	70,239,422

Notes

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Account 201 - Common Stock Issued			
2	No Par Value	200,000,000		
3	Restricted shares			
4	Total Common	200,000,000		
5				
6				
7	Account 204 - Preferred Stock Issued	10,000,000		
8				
9				
10	Cumulative			
11				
12				
13	Total Preferred	10,000,000		
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CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
60,076,752	869,342,827			104,416	2,718,992	2
						3
60,076,752	869,342,827			104,416	2,718,992	4
						5
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.
(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Equity transactions of subsidiaries	8,089,025
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40	TOTAL	8,089,025

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

CAPITAL STOCK EXPENSE (Account 214)

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

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Stock - no par	19,561,527
2		
3		
4		
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21		
22	TOTAL	19,561,527

Schedule Page: 254 Line No.: 1 Column: b

Beginning Balance	$	(14,977,565)
Issuance of common stock		14,798
TAX BENEFIT - OPTIONS EXERCISED		1,867,478
Excess Tax Benefits on stock compensation		(464,677)
Stock compensation accrual		(6,001,560)
Ending Balance	$	(19,561,527)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

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

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	FMBS - SERIES A - 7.53% DUE 05/05/2023	5,500,000	42,712
2	FMBS - SERIES A - 7.54% DUE 5/05/2023	1,000,000	7,766
3	FMBS - SERIES A - 7.39% DUE 5/11/2018	7,000,000	54,364
4	FMBS - SERIES A - 7.45% DUE 6/11/2018	15,500,000	170,597
5	FMBS - SERIES A - 7.18% DUE 8/11/2023	7,000,000	54,364
6	ADVANCE ASSOCIATED-AVISTA CAPITAL II (ToPRS)	51,547,000	1,296,086
7	FMBS - 6.37% SERIES C	25,000,000	158,304
8	FMBS - 5.45% SERIES	90,000,000	1,432,081
9	FMBS - 6.25% SERIES	150,000,000	2,180,435
10	FMBS - 5.70% SERIES	150,000,000	4,924,304
11	FMBS - 5.95% SERIES	250,000,000	3,081,419
12	FMBS - 5.125% SERIES	250,000,000	2,859,788
13	COLSTRIP 2010A PCRBs DUE 2032	66,700,000	
14	COLSTRIP 2010B PCRBs DUE 2034	17,000,000	
15	FMBS - 3.89% SERIES	52,000,000	383,338
16	FMBS - 5.55% SERIES	35,000,000	258,834
17	4.45% SERIES DUE 12-14-2041	85,000,000	692,833
18	4.23% SERIES DUE 11-29-2047	80,000,000	730,833
19	FMBS - 0.84% SERIES	90,000,000	512,138
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	1,428,247,000	18,840,196

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

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

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
05-06-1993	05-05-2023	05-06-1993	05-05-2023	5,500,000	414,150	1
05-07-1993	05-05-2023	05-07-1993	05-05-2023	1,000,000	75,400	2
05-11-1993	05-11-2018	05-11-1993	05-11-2018	7,000,000	517,300	3
06-09-1993	06-11-2018	06-09-1993	06-11-2018	15,500,000	1,154,750	4
08-12-1993	08-11-2023	08-12-1993	08-11-2023	7,000,000	502,600	5
06-03-1997	06-01-2037	06-03-1997	06-01-2037	51,547,000	467,113	6
06-19-1998	06-19-2028	06-19-1998	06-19-2028	25,000,000	1,592,500	7
11-18-2004	12-01-2019	11-18-2004	12-01-2019	90,000,000	4,905,000	8
11-17-2005	12-01-2035	11-17-2005	12-01-2035	150,000,000	9,375,000	9
12-15-2006	07-01-2037	12-15-2006	07-01-2037	150,000,000	8,550,000	10
04-02-2008	06-01-2018	04-02-2008	06-01-2018	250,000,000	14,875,000	11
09-22-2009	04-01-2022	09-22-2009	04-01-2022	250,000,000	12,812,500	12
12-15-2010	10-1-2032	12-15-2010	10-1-2032	66,700,000		13
12-15-2010	3-1-2034	12-15-2010	3-1-2034	17,000,000		14
12-20-2010	12-20-2020	12-20-2010	12-20-2020	52,000,000	2,022,800	15
12-20-2010	12-20-2040	12-20-2010	12-20-2040	35,000,000	1,942,500	16
12-14-2011	12-14-2041	12-14-2011	12-14-2041	85,000,000	3,782,500	17
11-30-2012	11-29-2047	11-30-2012	11-29-2047	80,000,000	3,384,000	18
8-14-2013	8-14-2016	8-14-2013	8-13-2016	90,000,000	289,800	19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				1,428,247,000	66,662,913	33

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) X An Original (2) _ A Resubmission	04/11/2014	2013/Q4

FOOTNOTE DATA

Schedule Page: 256 Line No.: 6 Column: a

(1) Electric
(2) Gas

Schedule Page: 256 Line No.: 13 Column: b

The Company reacquired this debt in 2010. These bonds have not been retired or canceled; the Company plans, based on liquidity needs and market conditions, to remarket these bonds at a future date.

Schedule Page: 256 Line No.: 13 Column: c

The Company reaquired these bonds in 2010.

Schedule Page: 256 Line No.: 14 Column: b

The Company reacquired this debt in 2010. These bonds have not been retired or canceled; the Company plans, based on liquidity needs and market conditions, to remarket these bonds at a future date.

Schedule Page: 256 Line No.: 14 Column: c

The Company reaquired these bonds in 2010.

Schedule Page: 256 Line No.: 19 Column: a

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

1. Order of the Washington Utilities and Transportation Commission entered July 13, 2011, as amended on August 24, 2011 in Docket No. U-111176;

2. Order of the Idaho Public Utilities Commission, Order No. 32338, entered August 25, 2011;

3. Order of the Public Utility Commission of Oregon, Order No. 11334, entered August 26, 2011;

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

Schedule Page: 256 Line No.: 19 Column: c

Expenses may change as invoices related to this issuance become known.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

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

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

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	111,076,833
2		
3		
4	Taxable Income Not Reported on Books	
5		4,167,283
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		134,569,130
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		8,543,211
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		-188,476,610
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	129,011,557
28	Show Computation of Tax:	
29	State Tax	2,066,358
30	Federal Tax Net Income less state tax	131,077,915
31		
32	Federal Tax @ 35%	45,877,270
33		
34	Prior Year & Misc True Ups	-6,225,476
35	Cabinet Gorge Tax Credits	-161,682
36	Total Federal Expense	39,490,112
37		
38		
39		
40		
41		
42		
43		
44		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	FEDERAL:					
2	Income Tax 2010	-868,026			253,118	1,283,663
3	Income Tax 2011	4,138,388		-127,744		-1,313,384
4	Income Tax 2012	1,429,077		-4,182,457	-3,626,826	1,141,098
5	Income Tax (Current)			42,305,967	44,861,559	-1,111,375
6	Retained Earnings					
7	Prior Retained Earnings	-1,392,676				-1
8	Prior Retained Earnings	-2,070,474				
9	Prior Retained Earnings	-1,994,624		-129,426		
10	Current Retained Earnings			-483,257		
11	Total Federal	-758,335		37,383,083	41,487,851	1
12						
13	STATE OF WASHINGTON:					
14	Property Tax (2012)	10,622,012		298,233	10,919,839	
15	Property Tax (2013)			12,100,002	1,035	
16	Excise Tax (2010)	-22,495				
17	Excise Tax (2012)	2,327,224		-33,351	2,293,873	
18	Excise Tax (2013)			24,687,534	21,825,161	
19	Natural Gas Use Tax	610		4,983	4,668	8,182
20	Municipal Occupation Tax	2,542,334		23,002,889	22,492,794	
21	Sales & Use Tax (2006)	-8,173				8,173
22	Sales & Use Tax (2011)	12				-12
23	Sales & Use Tax (2012)	54,903			50,415	-15,149
24	Sales & Use Tax (2013)			631,368	535,307	6,988
25	Motor Vehicle Tax (2013)			124,978	124,978	
26	Total Washington	15,516,427		60,816,636	58,248,070	8,182
27						
28	STATE OF IDAHO:					
29	Income Tax (2010)	-4,633		4,633		
30	Income Tax (2011)	135,640		117,539	262,836	9,657
31	Income Tax (2012)	-22,958		33,604	10,646	
32	Income Tax (2013)			896,539	960,000	
33	Property Tax (2012)	3,276,997		-23,426	2,900,575	
34	Property Tax (2013)			6,626,716	3,307,099	
35	Motor Vehicle Tax (2013)			26,152	26,152	
36	Sales & Use Tax (2005)	436		-436		
37	Sales & Use Tax (2012)	2,169			6,554	4,385
38	Sales & Use Tax (2013)			103,170	94,742	-4,385
39	Irrigation Credits (2012)					
40	KWH Tax (2012)	35,680		-3,625	32,054	
41	TOTAL	22,309,642		129,012,148	129,217,988	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
162,519						2
2,697,260		-127,744				3
2,014,544		-400,213			-3,782,244	4
-3,666,967		34,682,140			7,623,827	5
						6
-1,392,677						7
-2,070,474						8
-2,124,050					-129,426	9
-483,257					-483,257	10
-4,863,102		34,154,183			3,228,900	11
						12
						13
405		137,233			161,000	14
12,098,968		9,652,002			2,448,000	15
-22,495						16
		-49,363			16,012	17
2,862,373		18,969,454			5,718,080	18
9,107		5,252			-269	19
3,052,429		17,349,476			5,653,413	20
						21
						22
-10,661						23
103,048					631,368	24
					124,978	25
18,093,174		46,064,054			14,752,582	26
						27
						28
					4,633	29
					117,539	30
		26,883			6,721	31
-63,461		698,624			197,915	32
352,996		-23,426				33
3,319,617		5,402,049			1,224,667	34
					26,152	35
					-436	36
						37
4,043					103,170	38
						39
1		-3,626				40
22,103,801		101,884,296			27,127,852	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	KWH Tax (2013)			339,192	320,008	
2	Franchise Tax (2012)	1,480,762			1,480,762	
3	Franchise Tax (2013)			4,409,709	2,835,752	
4	Total Idaho	4,904,093		12,529,767	12,237,180	9,657
5						
6	STATE OF MONTANA:					
7	Income Tax (2010)	7,714		-7,714		
8	Income Tax (2011)	389,771		-392,990		3,219
9	Income Tax (2012)	27,779		-95,790		
10	Income Tax (2013)			601,062	417,384	
11	Property Tax (2012)	3,600,374		27,500	3,627,443	
12	Property Tax (2013)			8,163,129	4,091,832	
13	Colstrip Generation Tax			2,948	2,948	
14	KWH Tax (2012)	279,528			279,528	
15	KWH Tax (2013)			961,868	794,967	
16	Motor Vehicle Tax (2013)			3,147	3,147	
17	Consumer Council Tax	34		-1	22	
18	Public Commission Tax	113		4	74	
19	Total Montana	4,305,313		9,263,163	9,217,345	3,219
20						
21	STATE OF OREGON:					
22	Income Tax (2010)	-138,944		152,854	403,286	389,376
23	Income Tax (2011)	7,398		11,679	-295,000	-314,077
24	Income Tax (2012)	231,742		-256,743		
25	Income Tax (2013)			886,066	100,000	
26	Property Tax (2012)	-1,976,033		1,975,925	-107	1
27	Property Tax (2013)			2,249,347	4,335,454	
28	Motor Vehicle Tax (2013)			1,607	1,607	
29	BETC Credit (2010 and Prior)	1,448		38,202		-57,133
30	BETC Credit (2011)	-365,909		310,014		25,933
31	BETC Credit (2012)	-18,696				-39,093
32	Glendale Regulatory Cr. 2008	-210,889		35,397		175,492
33	Glendate Regulatory Cr. 2009	70,289				-105,200
34	Franchise Tax (2010)	681				-168
35	Franchise Tax (2011)	26,916				-26,916
36	Franchise Tax (2012)	748,205			750,757	27,083
37	Franchise Tax (2013)			3,573,552	2,683,738	
38	Total Oregon	-1,623,792		8,977,900	7,979,735	75,298
39						
40	STATE OF CALIFORNIA:					
41	TOTAL	22,309,642		129,012,148	129,217,988	

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
19,184		339,854			-662	1
						2
1,573,957		3,212,543			1,197,167	3
5,206,337		9,652,901			2,876,866	4
						5
						6
					-7,714	7
					-392,990	8
-68,011		-95,790				9
183,678		601,062				10
431		27,500				11
4,071,297		8,163,129				12
		2,948				13
						14
166,901		961,868				15
					3,147	16
11						17
43		3				18
4,354,350		9,660,720			-397,557	19
						20
						21
					152,854	22
					11,679	23
-25,001		-64,186			-192,557	24
786,066		221,516			664,550	25
		1,022,574			953,352	26
-2,086,107		1,172,534			1,076,812	27
					1,607	28
-17,483					38,202	29
-29,962					310,014	30
-57,789						31
					35,397	32
-34,911						33
513						34
						35
24,531						36
889,814					3,573,552	37
-550,329		2,352,438			6,625,462	38
						39
						40
22,103,801		101,884,296			27,127,852	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	Income Tax (2011)	-6,325		5,525		
2	Income Tax (2012)	-1,600		1,600		
3	Income Tax (2013)				1,600	
4	Total California	-7,925		7,125	1,600	
5						
6	MISCELLANEOUS STATES:					
7	Income Tax (2012)	-1		1		
8	Income Tax (2013)			-34,438		-88,175
9	Total Misc States	-1		-34,437		-88,175
10						
11	COUNTY & MUNICIPAL					
12	Vehicle Excise Tax			5,005	5,005	
13	WA Renewable Energy	-561		-25,260	-25,260	
14	Misc.	-25,577		89,166	66,462	-8,182
15	Total County	-26,138		68,911	46,207	-8,182
16						
17						
18						
19						
20						
21						
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24						
25						
26						
27						
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36						
37						
38						
39						
40						
41	TOTAL	22,309,642		129,012,148	129,217,988	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
-800					5,525	1
					1,600	2
-1,600						3
-2,400					7,125	4
						5
						6
					1	7
-122,613					-34,438	8
-122,613					-34,437	9
						10
						11
					5,005	12
-561					-25,260	13
-11,055					89,166	14
-11,616					68,911	15
						16
						17
						18
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						40
22,103,801		101,884,296			27,127,852	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%						
6		12,420,638	411	-186,271			
7							
8	TOTAL	12,420,638		-186,271			
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Gas Property (100%	62,172			411	15,996	
11		130,248			411	23,760	
12	TOTAL PROPERTY	192,420				39,756	
13							
14							
15							
16							
17							
18							
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ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
			5
12,234,367			6
			7
12,234,367			8
			9
46,176			10
106,488			11
152,664			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
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			47
			48

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

OTHER DEFFERED CREDITS (Account 253)

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

Line No.	Description and Other Deferred Credits	Balance at Beginning of Year	DEBITS		Credits	Balance at End of Year
			Contra Account	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Defer Gas Exchange (253028)	1,499,990			10	1,500,000
2	Rathdrum Refund (253120)	239,576	550	33,822		205,754
3	NE Tank Spil (253130)	16,797	186	15		16,782
4	Bills Pole Rentals (253140)	280,960			15,379	296,339
5	CR-CS2 GE LTSA (253150)	2,999,302	232	996,162		2,003,140
6	CR-Credit Resource Actg	1,577,531	186	676,085		901,446
7	DOC EECE Grant (253155)	752,550	136	481,170		271,380
8	Defer Comp Retired Execs (253900)	59,249	431	22,994		36,255
9	Defer Comp Active Execs (253910)	8,806,150			364,302	9,170,452
10	Executive Incent Plan (253920)	140,000				140,000
11	Unbilled Revenue (253990)	683,441			364,833	1,048,274
12	WA Energy Recovery Mechanism	8,756,638	186	8,756,638	8,024,194	8,024,194
13	Misc Deferred Credits	80,772	186	238,605	296,202	138,369
14	REC Deferral	277,010	186	119,177	1,449,115	1,606,948
15						
16						
17						
18						
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46						
47	TOTAL	26,169,966		11,324,668	10,514,035	25,359,333

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	276,927,675	14,480,652	
3	Gas	102,114,468	5,902,039	
4	Other	40,174,470	7,562,843	
5	TOTAL (Enter Total of lines 2 thru 4)	419,216,613	27,945,534	
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	419,216,613	27,945,534	
10	Classification of TOTAL			
11	Federal Income Tax	408,150,290	27,945,534	
12	State Income Tax	11,066,323		
13	Local Income Tax			

NOTES

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2014	Year/Period of Report End of 2013/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
						291,408,327	2
-61,912						107,954,595	3
						47,737,313	4
-61,912						447,100,235	5
							6
							7
							8
-61,912						447,100,235	9
							10
-61,912						436,033,912	11
						11,066,323	12
							13

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Electric	17,538,524	-292,588	512,038
4				
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	17,538,524	-292,588	512,038
10	Gas			
11	Gas	-1,803,226	-1,854,753	
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	-1,803,226	-1,854,753	
18	Other	229,946,659	-3,863,652	
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	245,681,957	-6,010,993	512,038
20	Classification of TOTAL			
21	Federal Income Tax	245,681,957	-6,010,993	512,038
22	State Income Tax			
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
3,570,506					-1,062,903	19,241,501	3
							4
							5
							6
							7
							8
3,570,506					-1,062,903	19,241,501	9
							10
					-198,635	-3,856,614	11
							12
							13
							14
							15
							16
					-198,635	-3,856,614	17
-5,268,539			74,354,921			146,459,547	18
-1,698,033			74,354,921		-1,261,538	161,844,434	19
							20
-1,698,033			74,354,921		-1,261,538	161,844,434	21
							22
							23

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Idaho Investment Tax Credit (254005)	12,308,073	190	6,898,515		5,409,558
2	Oregon BETC Credit (254010)	1,553,984	190	1,053,984		500,000
3	Noxon, ITC (254025)	3,344,017	190	50,154		3,293,863
4	Settled Int Rate Swaps (254090)				12,965,590	12,965,590
5	Unsettled Int Rate Swaps (254100)				33,543,258	33,543,258
6	Oregon Commercial Fee (254120)	(1,943)		1	1,944	
7	FAS 109 Invest Credit (254180)	103,608	190	21,408		82,200
8	Nez Perce (254220)	682,364	557	22,008		660,356
9	Oregon Senate Bill (254250)	(70,470)	407	1,429	71,899	
10	Decoupling Rebate (254328)	5,531	407	3,252		2,279
11	BPA Parallel Cap (254331)				5,397,106	5,397,106
12	Reg Liability WA Rec's (254360)	93,222	186	93,222		
13	Unrealized Currency Exchange (254399)	3,602	143	59,467	55,865	
14	Mark to Market ST (254740)	1		1		
15	Colstrip/CS2	1		1		
16	Idaho PCA	18,566,192	182	18,566,192	9,879,394	9,879,394
17	SWAPS on FMBS	18,656,780	427	18,656,780		
18	Roseburg/Medford				8,726	8,726
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
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32						
33						
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40						
41	TOTAL	55,244,962		45,426,414	61,923,782	71,742,330

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ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	331,866,712	315,137,034
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	289,604,042	286,567,954
5	Large (or Ind.) (See Instr. 4)	113,631,878	119,588,721
6	(444) Public Street and Highway Lighting	7,266,653	7,240,388
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	1,103,974	1,025,713
10	TOTAL Sales to Ultimate Consumers	743,473,259	729,559,810
11	(447) Sales for Resale	143,390,565	148,004,414
12	TOTAL Sales of Electricity	886,863,824	877,564,224
13	(Less) (449.1) Provision for Rate Refunds	2,047,837	
14	TOTAL Revenues Net of Prov. for Refunds	884,815,987	877,564,224
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	590,953	559,797
18	(453) Sales of Water and Water Power	432,332	468,800
19	(454) Rent from Electric Property	3,023,492	2,971,731
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	135,207,886	124,709,799
22	(456.1) Revenues from Transmission of Electricity of Others	25,386,252	11,641,754
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	164,640,915	140,351,881
27	TOTAL Electric Operating Revenues	1,049,456,902	1,017,916,105

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ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
3,745,255	3,608,626	321,098	318,692	2
				3
3,146,819	3,127,158	40,202	39,869	4
1,979,324	2,099,648	1,386	1,395	5
25,818	25,878	527	503	6
				7
				8
12,193	11,695	99	94	9
8,909,409	8,873,005	363,312	360,553	10
4,409,585	5,634,398			11
13,318,994	14,507,403	363,312	360,553	12
				13
13,318,994	14,507,403	363,312	360,553	14

Line 12, column (b) includes $ -543,700 of unbilled revenues.

Line 12, column (d) includes -22,931 MWH relating to unbilled revenues

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SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	RESIDENTIAL SALES (440)					
2	1 Residential Service	3,609,234	305,867,846	305,849	11,801	0.0847
3	2 Residential Service					
4	3 Residential Service					
5	12 Res. & Farm Gen. Service	80,152	10,246,198	13,433	5,967	0.1278
6	15 MOPS II Residential					
7	22 Res. & Farm Lg. Gen. Service	49,768	4,035,218	80	622,100	0.0811
8	30 Pumping-Special	1	172	1	1,000	0.1720
9	32 Res. & Farm Pumping Service	9,815	1,051,972	1,735	5,657	0.1072
10	48 Res. & Farm Area Lighting	4,366	1,034,774			0.2370
11	49 Area Lighting-High-Press.	243	74,243			0.3055
12	56 Centralia Refund					
13	95 Wind Power		150,533			
14	72 Residential Service					
15	73 Residential Service					
16	74 Residential Service					
17	76 Residential Service					
18	77 Residential Service					
19	58A Tax Adjustment		-48,749			
20	58 Tax Adjustment		9,076,204			
21	SubTotal	3,753,579	331,488,411	321,098	11,690	0.0883
22	Residential-Unbilled	-8,324	378,300			-0.0454
23	Total Residential Sales	3,745,255	331,866,711	321,098	11,664	0.0886
24						
25	COMMERCIAL SALES (442)					
26	2 General Service					
27	3 General Service					
28	11 General Service	847,692	91,612,629	36,121	23,468	0.1081
29	12 Res. & Farm Gen. Service					
30	16 MOPS II Commercial					
31	19 Contract-General Service					
32	21 Large General Service	1,864,976	158,010,187	2,959	630,272	0.0847
33	25 Extra Lg. Gen. Service	349,407	21,122,418	13	26,877,462	0.0605
34	28 Contract-Extra Large Serv					
35	31 Pumping Service	92,915	7,564,547	1,109	83,783	0.0814
36	47 Area Lighting-Sod. Vap	6,192	1,340,416			0.2165
37	49 Area Lighting-High-Press.	2,491	574,892			0.2308
38	56 Centralia Refune					
39	95 Wind Power		76,742			
40	74 Large General Service					
41	TOTAL Billed	13,341,925	887,407,524	363,312	36,723	0.0665
42	Total Unbilled Rev.(See Instr. 6)	-22,931	-543,700	0	0	0.0237
43	TOTAL	13,318,994	886,863,824	363,312	36,660	0.0666

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	75 Large General Service					
2	76 Large General Service					
3	77 General Service					
4	58A Tax Adjustment		-47,846			
5	58 Tax Adjustment		10,473,535			
6	SubTotal	3,163,673	290,727,520	40,202	78,694	0.0919
7	Commercial-Unbilled	-16,854	-1,123,478			0.0667
8	Total Commercial	3,146,819	289,604,042	40,202	78,275	0.0920
9						
10	INDUSTRIAL SALES (442)					
11	2 General Service					
12	3 General Service					
13	8 Lg Gen Time of Use					
14	11 General Service	9,793	1,089,656	254	38,555	0.1113
15	12 Res. & Farm Gen. Service					
16	21 Large General Service	210,366	17,199,611	162	1,298,556	0.0818
17	25 Extra Lg. Gen. Service	1,673,070	87,564,664	18	92,948,333	0.0523
18	28 Contract - Extra Large Service					
19	29 Contract Lg. Gen. Service					
20	30 Pumping Service - Special	20,868	1,423,043	31	673,161	0.0682
21	31 Pumping Service	58,561	4,920,693	776	75,465	0.0840
22	32 Pumping Svc Res & Firm	4,131	345,878	145	28,490	0.0837
23	47 Area Lighting-Sod. Vap.	226	48,137			0.2130
24	49 Area Lighting - High-Press	61	13,033			0.2137
25	95 Wind Power		1,728			
26	48 Area Lighting-Sod. Vap.	1	344			0.3440
27	73 General Service					
28	74 Large General Service					
29	75 Large General Service					
30	76 Pumping Service					
31	77 General Service					
32	58A Tax Adjustment		-1,128			
33	58 Tax Adjustment		824,741			
34	SubTotal	1,977,077	113,430,400	1,386	1,426,462	0.0574
35	Industrial-Unbilled	2,247	201,478			0.0897
36	Total Industrial	1,979,324	113,631,878	1,386	1,428,084	0.0574
37						
38	STREET AND HWY LIGHTING (444)					
39	6 Mercury Vapor St. Ltg.					
40	7 HP Sodium Vap. St. Ltg					
41	TOTAL Billed	13,341,925	887,407,524	363,312	36,723	0.0665
42	Total Unbilled Rev.(See Instr. 6)	-22,931	-543,700	0	0	0.0237
43	TOTAL	13,318,994	886,863,824	363,312	36,660	0.0666

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	11 General Service	105	12,522	5	21,000	0.1193
2	41 Co-Owned St. Lt. Service	218	42,290	16	13,625	0.1940
3	42 Co-Owned St. Lt. Service	20,626	6,530,762	394	52,350	0.3166
4	High-Press. Sod. Vap.					
5	43 Cust-Owned St. Lt. Energy	9	911	1	9,000	0.1012
6	and Maint. Service					
7	44 Cust-Owned St. Lt. Energy	692	69,287	30	23,067	0.1001
8	and Maint. Svce - High-Pres					
9	Sodium Vapor					
10	45 Cust. Owned St. Lt. Energy Svc	1,385	97,395	16	86,563	0.0703
11	46 Cust. Owned St. Lt. Energy Svc	2,783	257,661	65	42,815	0.0926
12	58A Tax Adjustment		-730			
13	58 Tax Adjustment		256,556			
14	SubTotal	25,818	7,266,654	527	48,991	0.2815
15	Street & Hwy Lighting-Unbilled					
16	Total Street & Hwy Lighting	25,818	7,266,654	527	48,991	0.2815
17						
18	OTHER SALES TO PUBLIC					
19	(445)					
20	None					
21						
22	INTERDEPARTMENTAL SALES	12,193	1,102,127	99	123,162	0.0904
23	58 Tax Adjustment		1,847			
24	Total Interdepartmental	12,193	1,103,974	99	123,162	0.0905
25						
26	SALES FOR RESALE (447)	4,409,585	143,390,565			0.0325
27	61 Sales to Other Utilities (NDA)					
28						
29						
30	Total Sales for Resale	4,409,585	143,390,565			0.0325
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	13,341,925	887,407,524	363,312	36,723	0.0665
42	Total Unbilled Rev.(See Instr. 6)	-22,931	-543,700	0	0	0.0237
43	TOTAL	13,318,994	886,863,824	363,312	36,660	0.0666

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	BP Energy Company	SF	ISDA			
2	BP Energy Company	SF	Tariff 9			
3	Black Hills Power, Inc.	SF	Tariff 9			
4	Bonneville Power Administration	LF	Tariff 8			
5	Bonneville Power Administration	LF	ACS-06			
6	Bonneville Power Administration	SF	Tariff 9			
7	Bonneville Power Administration	LF	Tariff 12			
8	British Columbia Hydro and Power Author	LF	Tariff 12			
9	Brookfield Energy Marketing LP	SF	Tariff 9			
10	Burbank, City of	SF	Tariff 9			
11	Calpine Energy Services LP	SF	Tariff 9			
12	Cargill Power Markets, LLC	SF	Tariff 9			
13	Chelan County PUD No. 1	SF	Tariff 9			
14	Chelan County PUD No. 1	LF	Tariff 12			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,line 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
			5,224,079	5,224,079	1
255,866		7,207,638		7,207,638	2
2,400		44,680		44,680	3
16,412		579,106		579,106	4
1,783		47,191		47,191	5
161,486		4,510,379		4,510,379	6
80		2,607		2,607	7
39		1,604		1,604	8
1,200		164,000		164,000	9
400		6,200		6,200	10
276,556		6,399,923		6,399,923	11
176,441		5,172,393		5,172,393	12
8,800		262,940		262,940	13
1		41		41	14
0	0	0	0	0	
4,409,585	5,179,351	119,562,425	18,648,789	143,390,565	
4,409,585	**5,179,351**	**119,562,425**	**18,648,789**	**143,390,565**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for long-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Citigroup Energy, Inc.	SF	Tariff 9			
2	Clark County PUD No. 1	SF	Tariff 9			
3	Clatskanie Peoples PUD	SF	Tariff 9			
4	Constellation Energy Commodities Group	SF	Tariff 9			
5	Douglas County PUD No. 1	SF	Tariff 9			
6	EDF Trading North America, LLC	SF	Tariff 9			
7	Eugene Water & Electric Board	SF	Tariff 9			
8	Exelon Generation Company, LLC	SF	Tariff 9			
9	Grant County PUD No. 2	SF	Tariff 9			
10	Grant County PUD No. 2	LF	Tariff 12			
11	Grant County PUD No. 2	SF	Tariff 9			
12	Iberdrola Renewables, LLC	SF	Tariff 9			
13	Iberdrola Renewables, LLC	SF	Tariff 9			
14	Iberdrola Renewables, LLC	SF	Tariff 9			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,line 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
33,280		913,262		913,262	1
21,250		834,107		834,107	2
4,225		141,145		141,145	3
2,574		68,540		68,540	4
7,880		289,011		289,011	5
90,784		2,765,275		2,765,275	6
12,935		462,685		462,685	7
17,202		514,103		514,103	8
8,097		248,577		248,577	9
9		269		269	10
	1,800			1,800	11
337,924		9,934,031		9,934,031	12
	353,750			353,750	13
	1,000			1,000	14
0	0	0	0	0	
4,409,585	5,179,351	119,562,425	18,648,789	143,390,565	
4,409,585	**5,179,351**	**119,562,425**	**18,648,789**	**143,390,565**	

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW): Average Monthly NCP Demand (e)	Actual Demand (MW): Average Monthly CP Demand (f)
1	Idaho Power Company	SF	Tariff 9			
2	Idaho Power Company	LF	Tariff 12			
3	Idaho Power Balancing	SF	Tariff 9			
4	J. Aron & Company	SF	Tariff 9			
5	JP Morgan Ventures Energy	SF	Tariff 9			
6	Macquarie Energy, LLC	SF	Tariff 9			
7	Mizuho Securities USA, Inc.	SF	ISDA			
8	Modesto Irrigation District	SF	Tariff 9			
9	Morgan Stanley Capital Group, Inc.	SF	Tariff 9			
10	Morgan Stanley Capital Group, Inc.	SF	Tariff 9			
11	Morgan Stanley Capital Group, Inc.	SF	Tariff 9			
12	Morgan Stanley Capital Group, Inc.	SF	Tariff 9			
13	NaturEner Power Watch, LLC	SF	Tariff 9			
14	NaturEner Power Watch, LLC	LF	Tariff 12			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

SALES FOR RESALE (Account 447) (Continued)

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

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

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
26,334		855,198		855,198	1
35		1,236		1,236	2
131,836		4,656,686		4,656,686	3
20,025		583,275		583,275	4
59,432		1,574,545		1,574,545	5
113,663		3,244,411		3,244,411	6
			-2,013,194	-2,013,194	7
4,392		186,616		186,616	8
162,693		5,060,972		5,060,972	9
	62,748			62,748	10
	870,312			870,312	11
	41,650			41,650	12
4,597		145,206		145,206	13
33		1,134		1,134	14
0	0	0	0	0	
4,409,585	5,179,351	119,562,425	18,648,789	143,390,565	
4,409,585	**5,179,351**	**119,562,425**	**18,648,789**	**143,390,565**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2014	Year/Period of Report End of 2013/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	NaturEner Power Watch, LLC	SF	Tariff 9			
2	NaturEner Power Watch, LLC	SF	Tariff 9			
3	NaturEner Power Watch, LLC	SF	Tariff 9			
4	Newedge USA, LLC	SF	ISDA			
5	NextEra Energy Power Market	SF	Tariff 9			
6	Noble America Gas & Power	SF	Tariff 9			
7	NorthWestern Energy LLC	SF	Tariff 9			
8	NorthWestern Energy LLC	LF	Tariff 12			
9	NorthWestern Energy LLC	LF	Tariff 9			
10	NorthWestern Energy LLC	SF	Tariff 10			
11	Okanogan County PUD	SF	Tariff 9			
12	PacifiCorp	SF	Tariff 9			
13	PacifiCorp	LF	Tariff 12			
14	PacifiCorp	LF	Tariff 9			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

SALES FOR RESALE (Account 447) (Continued)

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

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

4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)

5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.

6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.

8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.

9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,line 24.

10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
	98,416			98,416	1
	276,182			276,182	2
	10			10	3
			-5,420,862	-5,420,862	4
1,903		62,769		62,769	5
10,600		349,740		349,740	6
87,692		3,565,645		3,565,645	7
87		2,551		2,551	8
7,369		227,609		227,609	9
	1,165,955			1,165,955	10
11,730		466,691		466,691	11
135,355		4,435,355		4,435,355	12
250		7,668		7,668	13
4,691		144,842		144,842	14
0	0	0	0	0	
4,409,585	5,179,351	119,562,425	18,648,789	143,390,565	
4,409,585	**5,179,351**	**119,562,425**	**18,648,789**	**143,390,565**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Peaker LLC	LF	Tariff 9			
2	Pend Oreille Public Utility District	LF	Tariff 9			
3	Pend Oreille Public Utility District	LF	Tariff 9			
4	Pend Oreille Public Utility District	SF	Tariff 9			
5	Pend Oreille Public Utility District	LF	290 (PNCA)			
6	Portland General Electric Company	SF	Tariff 9			
7	Portland General Electric Company	LF	Tariff 12			
8	Powerex	SF	Tariff 9			
9	Powerex	SF	Tariff 10			
10	PPL EnergyPlus, LLC	SF	Tariff 9			
11	PPL EnergyPlus, LLC	SF	Tariff 9			
12	PPL EnergyPlus, LLC	LF	Tariff 9			
13	Puget Sound Energy	LF	Tariff 9			
14	Puget Sound Energy	SF	Tariff 9			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
	1,748,415			1,748,415	1
	438,141			438,141	2
14,658		466,298		466,298	3
55,496		1,614,827		1,614,827	4
	10,758			10,758	5
94,981		3,316,445		3,316,445	6
70		2,276		2,276	7
360,921		9,872,092		9,872,092	8
	80			80	9
	15,630			15,630	10
49,153		1,682,365		1,682,365	11
16,746		517,293		517,293	12
21,437		662,136		662,136	13
203,003		6,800,986		6,800,986	14
0	0	0	0	0	
4,409,585	5,179,351	119,562,425	18,648,789	143,390,565	
4,409,585	**5,179,351**	**119,562,425**	**18,648,789**	**143,390,565**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for long-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Puget Sound Energy	LF	Tariff 12			
2	Rainbow Energy Marketing	SF	Tariff 9			
3	Redding, City of	SF	Tariff 9			
4	Sacramento Municipal Utility District	SF	Tariff 9			
5	Sacramento Municipal Utility District	LF	Tariff 12			
6	Sacramento Municipal Utility District	LF	Tariff 9			
7	San Diego Gas & Electric Company	SF	Tariff 9			
8	Seattle City Light	SF	Tariff 9			
9	Seattle City Light	LF	Tariff 12			
10	Shell Energy N.A.	SF	Tariff 9			
11	Sierra Pacific Power Company	SF	Tariff 9			
12	Sierra Pacific Power Company	LF	Tariff 12			
13	Snohomish County PUD	SF	Tariff 9			
14	Southern California Edison Company	SF	Tariff 9			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			0	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,line 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
24		962		962	1
49,450		1,288,442		1,288,442	2
208		8,112		8,112	3
74,423		2,593,434		2,593,434	4
3		95		95	5
525,470		22,319,114		22,319,114	6
3,400		89,000		89,000	7
10,877		323,918		323,918	8
20		495		495	9
427,743		13,569,679		13,569,679	10
39,390		1,147,016		1,147,016	11
53		1,628		1,628	12
20,111		719,876		719,876	13
600		13,100		13,100	14
0	0	0	0	0	
4,409,585	5,179,351	119,562,425	18,648,789	143,390,565	
4,409,585	**5,179,351**	**119,562,425**	**18,648,789**	**143,390,565**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Sovereign Power	LF	Tariff 9			
2	Sovereign Power	LF	Tariff 9			
3	Tacoma Power	SF	Tariff 9			
4	Tacoma Power	LF	Tariff 12			
5	Tacoma Power	SF	Tariff 9			
6	Tacoma Power	SF	Tariff 10			
7	Tenaska Power Services Co.	SF	Tariff 9			
8	The Energy Authority	SF	Tariff 9			
9	TransAlta Energy Marketing	SF	Tariff 9			
10	Turlock Irrigation District	SF	Tariff 9			
11	United Materials of Great Falls, Inc.	SF	Tariff 10			
12	IntraCompany Wheeling	LF				
13	IntraCompany Generation	LF				
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,line 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
	77,884			77,884	1
10,572		333,022		333,022	2
19,074		466,425		466,425	3
1		63		63	4
	1,920			1,920	5
	60			60	6
79		7,376		7,376	7
39,232		1,219,986		1,219,986	8
143,449		4,338,517		4,338,517	9
8,600		249,846		249,846	10
	14,640			14,640	11
		-20,204,255	20,204,255		12
			654,511	654,511	13
					14
0	0	0	0	0	
4,409,585	5,179,351	119,562,425	18,648,789	143,390,565	
4,409,585	**5,179,351**	**119,562,425**	**18,648,789**	**143,390,565**	

Schedule Page: 310 Line No.: 1 Column: b
SWAP

Schedule Page: 310 Line No.: 4 Column: b
BPA Contract Terminates September 30, 2028.

Schedule Page: 310 Line No.: 5 Column: b
BPA Contract Terminates January 1, 2036.

Schedule Page: 310 Line No.: 7 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310 Line No.: 8 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310 Line No.: 14 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.1 Line No.: 10 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.1 Line No.: 13 Column: b
Capacity

Schedule Page: 310.2 Line No.: 2 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.2 Line No.: 7 Column: b
SWAP

Schedule Page: 310.2 Line No.: 10 Column: b
Capacity

Schedule Page: 310.2 Line No.: 11 Column: b
Capacity

Schedule Page: 310.2 Line No.: 14 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.3 Line No.: 2 Column: b
Capacity

Schedule Page: 310.3 Line No.: 3 Column: b
Capacity

Schedule Page: 310.3 Line No.: 4 Column: b
SWAP

Schedule Page: 310.3 Line No.: 8 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.3 Line No.: 9 Column: b
NorthWestern Energy LLC sale expires October 31, 2018.

Schedule Page: 310.3 Line No.: 13 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.3 Line No.: 14 Column: b
PacifiCorp sale terminates October 31, 2018.

Schedule Page: 310.4 Line No.: 1 Column: b
Peaker, LLC capacity contract terminates December 31, 2016.

Schedule Page: 310.4 Line No.: 2 Column: b
Contract expires 9/30/2014.

Schedule Page: 310.4 Line No.: 3 Column: b
Contract expires 9/30/2014.

Schedule Page: 310.4 Line No.: 5 Column: b
Contract expires 9/30/2014.

Schedule Page: 310.4 Line No.: 7 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.4 Line No.: 12 Column: b
PPL sale terminates October 31, 2018.

Schedule Page: 310.4 Line No.: 13 Column: b
Puget Sound Energy sale terminates October 31, 2018.

Schedule Page: 310.5 Line No.: 1 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.5 Line No.: 5 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.5 Line No.: 6 Column: b
Contract expires 2014.

Schedule Page: 310.5 Line No.: 9 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.5 Line No.: 12 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.6 Line No.: 1 Column: b
Sovereign Power contract terminates 1-31-2015

Schedule Page: 310.6 Line No.: 2 Column: b
Sovereign Power Contract terminates 1-31-2015

Schedule Page: 310.6 Line No.: 4 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.6 Line No.: 12 Column: a
Intracompany Wheeling

Schedule Page: 310.6 Line No.: 12 Column: b
IntraCompany Wheeling terminates 09/30/2023.

Schedule Page: 310.6 Line No.: 13 Column: a
Intracompany Generation - Sale of Ancillary Services

Schedule Page: 310.6 Line No.: 13 Column: b
IntraCompany Generation - Sale of Ancillary Services.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	281,941	405,853
5	(501) Fuel	24,772,509	27,965,080
6	(502) Steam Expenses	4,198,197	4,007,068
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,017,827	903,817
10	(506) Miscellaneous Steam Power Expenses	2,880,540	2,366,646
11	(507) Rents	33,093	21,917
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	33,184,107	35,670,381
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	457,703	496,860
16	(511) Maintenance of Structures	680,769	607,138
17	(512) Maintenance of Boiler Plant	6,100,955	4,845,432
18	(513) Maintenance of Electric Plant	1,172,747	584,214
19	(514) Maintenance of Miscellaneous Steam Plant	799,354	565,141
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	9,211,528	7,098,785
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	42,395,635	42,769,166
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	1,908,948	2,403,166
45	(536) Water for Power	1,303,492	1,177,037
46	(537) Hydraulic Expenses	7,200,656	7,432,593
47	(538) Electric Expenses	6,644,506	6,299,336
48	(539) Miscellaneous Hydraulic Power Generation Expenses	716,024	620,314
49	(540) Rents	6,851,497	6,810,597
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	24,625,123	24,743,043
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	549,213	583,198
54	(542) Maintenance of Structures	979,941	606,145
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,781,796	1,355,754
56	(544) Maintenance of Electric Plant	4,157,781	2,804,743
57	(545) Maintenance of Miscellaneous Hydraulic Plant	578,169	485,261
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	8,046,900	5,835,101
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	32,672,023	30,578,144

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	1,394,573	1,289,906
63	(547) Fuel	110,462,332	64,054,801
64	(548) Generation Expenses	2,146,858	1,693,501
65	(549) Miscellaneous Other Power Generation Expenses	462,952	619,292
66	(550) Rents	-27,127	50,652
67	TOTAL Operation (Enter Total of lines 62 thru 66)	114,439,588	67,708,152
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	1,080,319	1,867,043
70	(552) Maintenance of Structures	50,978	12,412
71	(553) Maintenance of Generating and Electric Plant	1,994,695	7,706,560
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	182,724	161,209
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	3,308,716	9,747,224
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	117,748,304	77,455,376
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	205,763,918	239,356,429
77	(556) System Control and Load Dispatching	965,965	864,537
78	(557) Other Expenses	121,667,121	145,305,655
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	328,397,004	385,526,621
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	521,212,966	536,329,307
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,476,590	2,165,264
84			
85	(561.1) Load Dispatch-Reliability	24,584	14,379
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,296,586	1,175,921
87	(561.3) Load Dispatch-Transmission Service and Scheduling	1,107,366	962,648
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development		
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	457,928	419,664
94	(563) Overhead Lines Expenses	525,234	468,930
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	17,926,901	17,551,614
97	(566) Miscellaneous Transmission Expenses	1,969,445	1,787,287
98	(567) Rents	101,823	115,925
99	TOTAL Operation (Enter Total of lines 83 thru 98)	25,886,457	24,661,632
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	1,095,334	2,123,807
102	(569) Maintenance of Structures	384,459	451,661
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software		
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,353,879	1,139,396
108	(571) Maintenance of Overhead Lines	1,473,050	1,750,864
109	(572) Maintenance of Underground Lines	21,166	8,377
110	(573) Maintenance of Miscellaneous Transmission Plant	49,081	96,193
111	TOTAL Maintenance (Total of lines 101 thru 110)	4,376,969	5,570,298
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	30,263,426	30,231,930

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	2,459,976	2,195,632
135	(581) Load Dispatching		
136	(582) Station Expenses	658,164	631,080
137	(583) Overhead Line Expenses	2,570,589	2,900,414
138	(584) Underground Line Expenses	1,208,803	1,054,524
139	(585) Street Lighting and Signal System Expenses	96,492	166,256
140	(586) Meter Expenses	2,535,810	2,249,211
141	(587) Customer Installations Expenses	723,178	676,051
142	(588) Miscellaneous Expenses	6,388,373	7,563,801
143	(589) Rents	165,290	352,108
144	TOTAL Operation (Enter Total of lines 134 thru 143)	16,806,675	17,789,077
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	1,693,053	1,720,093
147	(591) Maintenance of Structures	338,632	370,675
148	(592) Maintenance of Station Equipment	1,098,232	886,849
149	(593) Maintenance of Overhead Lines	8,701,264	8,225,646
150	(594) Maintenance of Underground Lines	1,093,965	1,007,658
151	(595) Maintenance of Line Transformers	863,170	972,946
152	(596) Maintenance of Street Lighting and Signal Systems	809,998	674,264
153	(597) Maintenance of Meters	33,257	62,373
154	(598) Maintenance of Miscellaneous Distribution Plant	433,209	495,770
155	TOTAL Maintenance (Total of lines 146 thru 154)	15,064,780	14,416,274
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	31,871,455	32,205,351
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	353,964	577,883
160	(902) Meter Reading Expenses	3,209,973	2,905,712
161	(903) Customer Records and Collection Expenses	8,851,168	8,191,471
162	(904) Uncollectible Accounts	2,534,687	2,129,547
163	(905) Miscellaneous Customer Accounts Expenses	237,659	229,446
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	15,187,451	14,034,059

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	20,642,475	24,468,409
169	(909) Informational and Instructional Expenses	1,040,149	1,111,618
170	(910) Miscellaneous Customer Service and Informational Expenses	201,012	176,221
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	21,883,636	25,756,248
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	7,402	7,948
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	7,402	7,948
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	24,995,618	36,662,334
182	(921) Office Supplies and Expenses	4,124,034	4,136,952
183	(Less) (922) Administrative Expenses Transferred-Credit	102,053	65,805
184	(923) Outside Services Employed	10,535,127	11,659,879
185	(924) Property Insurance	1,449,064	1,325,546
186	(925) Injuries and Damages	3,100,513	2,428,175
187	(926) Employee Pensions and Benefits	1,214,925	1,364,064
188	(927) Franchise Requirements	5,747	5,747
189	(928) Regulatory Commission Expenses	5,838,865	6,659,471
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	117	2,394
192	(930.2) Miscellaneous General Expenses	3,108,307	3,255,338
193	(931) Rents	927,319	1,032,665
194	TOTAL Operation (Enter Total of lines 181 thru 193)	55,197,583	68,466,760
195	Maintenance		
196	(935) Maintenance of General Plant	8,858,776	7,813,751
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	64,056,359	76,280,511
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	684,482,695	714,845,354

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	BP Corporation NA	SF	ISDA			
2	BP Energy Company	SF	WSPP			
3	Black Hills Power, Inc.	SF	WSPP			
4	Bonneville Power Administration	LF	WNP#3 Agr.			
5	Bonneville Power Administration	SF	WSPP			
6	Bonneville Power Administration	SF	Tariff #8			
7	Bonneville Power Administration	OS	BPA OATT			
8	Bonneville Power Administration	SF	BPA OATT			
9	Calpine Energy Services LP	SF	WSPP			
10	Cargill Power Markets	SF	WSPP			
11	Cargill Power Markets	SF	ISDA			
12	City of Spokane	LU	PURPA			
13	City of Spokane	IU	PURPA			
14	Chelan County PUD	IU	Rocky Reach			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
					16	16	1
38,848				1,553,875		1,553,875	2
1,400				43,650		43,650	3
374,969				15,334,596		15,334,596	4
102,299				2,792,256		2,792,256	5
22,229				694,642		694,642	6
					15,337	15,337	7
2,247				69,625	-173,859	-104,234	8
265,838				7,417,590		7,417,590	9
53,814				1,897,676		1,897,676	10
					-26,361	-26,361	11
52,576				2,385,697		2,385,697	12
136,888				6,361,454		6,361,454	13
-14,670							14
6,911,072	554,654	557,179	16,564,813	183,742,212	5,456,893	205,763,918	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Chelan County PUD	SF	WSPP			
2	Chelan County PUD	IU	Chelan Sys			
3	Clark County PUD No. 1	SF	WSPP			
4	Clatskanie PUD	SF	WSPP			
5	Constellation Energy Commodities Group	SF	WSPP			
6	Deep Creek Energy, LLC	IU	PURPA			
7	Douglas County PUD No. 1	LU	Wells			
8	Douglas County PUD No. 1	LU	Wells Settlement			
9	Douglas County PUD No. 1	IF	Wells			
10	Douglas County PUD No. 1	SF	WSPP			
11	Douglas County PUD No. 1	EX	305			
12	EDF Trading No America	SF	WSPP			
13	Eugene Water & Electric Board	SF	WSPP			
14	Exelon Generation Company, LLC	SF	WSPP			
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
6,028				164,923		164,923	1
292,601			11,824,813			11,824,813	2
13,797				286,251		286,251	3
954				18,942		18,942	4
2,000				48,300		48,300	5
158				8,397		8,397	6
131,448				1,535,590		1,535,590	7
36,891				1,043,812		1,043,812	8
177,116			4,740,000			4,740,000	9
9,409				335,108		335,108	10
	111,780	111,780		1,567,500	832	1,568,332	11
34,423				783,556		783,556	12
3,101				140,198		140,198	13
3,600				144,464		144,464	14
6,911,072	554,654	557,179	16,564,813	183,742,212	5,456,893	205,763,918	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2014	Year/Period of Report End of 2013/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Ford Hydro Limited Partnership	LU	PURPA			
2	Grant County PUD No. 2	LU	Priest Rapids			
3	Grant County PUD No. 2	SF	WSPP			
4	Grant County PUD No. 2	EX	FERC #104			
5	Hydro Technology Systems	IU	PURPA			
6	Iberdrola Renewables LLC	SF	WSPP			
7	Idaho County Power & Light	LU	PURPA			
8	Idaho Power Company	SF	WSPP			
9	Idaho Power Company - Balancing	SF	WSPP			
10	Inland Power & Light Company	RQ	208			
11	J. Aron & Company	SF	WSPP			
12	Jim White	LU	PURPA			
13	J P Morgan Ventures Energy LLC	SF	WSPP			
14	J P Morgan Ventures Energy LLC	LU	PPM Energy			
	Total					

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
3,463				196,604		196,604	1
346,963				5,932,312		5,932,312	2
34,067				924,659		924,659	3
					-24,461	-24,461	4
11,326				524,489		524,489	5
154,076				4,888,110		4,888,110	6
2,251				83,247		83,247	7
105,296				3,804,485		3,804,485	8
25				850		850	9
108				6,709		6,709	10
2,000				62,050		62,050	11
1,248				115,195		115,195	12
352				13,792		13,792	13
73,478				3,227,889		3,227,889	14
6,911,072	554,654	557,179	16,564,813	183,742,212	5,456,893	205,763,918	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2014	Year/Period of Report End of 2013/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	J P Morgan Ventures Energy LLC	SF	ISDA			
2	Kootenai Electric Cooperative	IU	PURPA			
3	Macquarie Energy LLC	SF	WSPP			
4	Mizuho Securities USA, Inc.	SF	ISDA			
5	Morgan Stanley Capital Group	SF	WSPP			
6	Morgan Stanley Capital Group	SF	ISDA			
7	Newedge USA LLC	SF	ISDA			
8	NextEra Energy Power Marketing LLC	SF	WSPP			
9	Noble America Gas & Power Corp.	SF	WSPP			
10	NorthWestern Energy LLC	SF	WSPP			
11	Okanogan County PUD No. 1	SF	WSPP			
12	PPL Energy Plus	SF	WSPP			
13	PacifiCorp	SF	WSPP			
14	Palouse Wind LLC	LU	PPA			
	Total					

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
10,741				267,308		267,308	2
38,322				1,171,359		1,171,359	3
					-296,989	-296,989	4
102,228				3,373,096		3,373,096	5
					2,149,774	2,149,774	6
					2,503,801	2,503,801	7
13,782				494,219		494,219	8
3,000				69,350		69,350	9
10,471				262,581		262,581	10
7,033				199,762		199,762	11
1,348,367				38,930,960		38,930,960	12
73,495				2,103,185		2,103,185	13
297,027				16,284,926		16,284,926	14
6,911,072	554,654	557,179	16,564,813	183,742,212	5,456,893	205,763,918	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Pend Oreille County PUD No. 1	SF	Pend O'			
2	Pend Oreille County PUD No. 1	SF	Pend O'			
3	Phillips Ranch	LU	PURPA			
4	Portland General Electric Company	EX	304			
5	Portland General Electric Company	EX	178			
6	Portland General Electric Company	SF	WSPP			
7	Potlatch Corporation	LU	PURPA			
8	Powerex Corp	SF	WSPP			
9	Puget Sound Energy	SF	WSPP			
10	Rainbow Energy Marketing Corp	SF	WSPP			
11	Rathdrum Power LLC	LF	Lancaster			
12	Sacramento Municipal Utility District	SF	WSPP			
13	Seattle City Light	SF	WSPP			
14	Sheep Creek Hydro	LU	PURPA			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
114,896				3,409,216		3,409,216	1
16,121	2,252	4,621		458,985	-49,470	409,515	2
63				2,899		2,899	3
	430,725	431,400					4
	9,168	9,378			-117,198	-117,198	5
5,704				142,086		142,086	6
214,080				9,188,314		9,188,314	7
51,304				2,519,211		2,519,211	8
45,139				1,394,567		1,394,567	9
19,953				530,392		530,392	10
1,656,292				25,529,976		25,529,976	11
1,400				52,350		52,350	12
17,712				433,305		433,305	13
9,583				354,596		354,596	14
6,911,072	554,654	557,179	16,564,813	183,742,212	5,456,893	205,763,918	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Shell Energy	SF	ISDA			
2	Shell Energy	SF	WSPP			
3	Sierra Pacific Power Company	SF	WSPP			
4	Snohomish County PUD No. 1	SF	WSPP			
5	Sovereign Power	IF	Sovereign			
6	Spokane County	LU	PURPA			
7	Stimson Lumber	IU	PURPA			
8	Tacoma Power	SF	WSPP			
9	Tenaska Power Services Company	SF	WSPP			
10	The Energy Authority	SF	WSPP			
11	TransAlta Energy Marketing	SF	WSPP			
12	IntraCompany Generation Services	OS	OATT			
13	Other - Inadvertent Interchange	EX				
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
					820,960	820,960	1
145,136				4,314,344		4,314,344	2
200				700		700	3
26,545				679,665		679,665	4
8,765				208,140		208,140	5
1,195				80,887		80,887	6
34,991				1,862,069		1,862,069	7
52,241				1,811,044		1,811,044	8
29,467				1,030,227		1,030,227	9
30,946				841,400		841,400	10
42,256				1,332,600		1,332,600	11
					654,511	654,511	12
	729						13
							14
6,911,072	554,654	557,179	16,564,813	183,742,212	5,456,893	205,763,918	

Schedule Page: 326 Line No.: 1 Column: a

Fianncial SWAP

Schedule Page: 326 Line No.: 7 Column: a

Ancillary Services - Spinning & Supplemental

Schedule Page: 326 Line No.: 8 Column: a

Non Monetary

Schedule Page: 326 Line No.: 11 Column: a

Financial SWAP

Schedule Page: 326.1 Line No.: 11 Column: a

Non Monetary

Schedule Page: 326.2 Line No.: 4 Column: a

Non Monetary

Schedule Page: 326.2 Line No.: 10 Column: a

Service to Deer Lake from Inland Power and Light. No demand charges associated with the agreement.

Schedule Page: 326.3 Line No.: 1 Column: a

Financial SWAP

Schedule Page: 326.3 Line No.: 4 Column: a

Financial SWAP

Schedule Page: 326.3 Line No.: 6 Column: a

Financial SWAP

Schedule Page: 326.3 Line No.: 7 Column: a

Financial SWAP

Schedule Page: 326.4 Line No.: 2 Column: a

Non Monetary

Schedule Page: 326.4 Line No.: 5 Column: a

Non Monetary

Schedule Page: 326.5 Line No.: 1 Column: a

Financial Swap

Schedule Page: 326.5 Line No.: 12 Column: a

Ancillary Services

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	PacifiCorp	PacifiCorp	PacifiCorp	LFP
2	Seattle City Light	Seattle City Light	Grant County PUD	LFP
3	Tacoma City Light	Tacoma City Light	Grant County PUD	LFP
4	Grant County Public Utility District	Grant County Public Utility Distr	Grant County Public Utility Distr	OS
5	Spokane Indian Tribes	Bonneville Power Administration	Spokane Indian Tribes	LFP
6	USBR	Bonneville Power Administration	East Greenacres	LFP
7	Consolidated Irrigation District	Bonneville Power Administration	Consolidated Irrigation District	LFP
8	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	FNO
9	City of Spokane	City of Spokane	Avista Corporation	OS
10	Stimpson	Plummer	Avista Corporation	OS
11	Hydro Tech Industries	Meyers Falls	Avista Corporation	OS
12	First Wind Energy Marketing	Palouse Wind	Avista Corporation	OS
13	Deep Creek Hydro	Deep Creek	Avista Corporation	OS
14	Bonneville Power Administration	Avista Corporation	Bonneville Power Administration	OS
15	Coral Power	Avista Corporation	Idaho Power Company	SFP
16	Coral Power	Bonneville Power Administration	Idaho Power Company	SFP
17	Cargill Power Markets	Bonneville Power Administration	Idaho Power Company	SFP
18	Cargill Power Markets	Northwestern Montana	Bonneville Power Administration	SFP
19	Cargill Power Markets	Northwestern Montana	Chelan County PUD	SFP
20	Cargill Power Markets	Idaho Power Company	Bonneville Power Administration	SFP
21	Morgan Stanley Capital Group	Bonneville Power Administration	Idaho Power Company	SFP
22	Morgan Stanley Capital Group	Bonneville Power Administration	Northwestern Montana	SFP
23	Morgan Stanley Capital Group	Northwestern Montana	Bonneville Power Administration	SFP
24	Morgan Stanley Capital Group	Northwestern Montana	Chelan County PUD	SFP
25	Morgan Stanley Capital Group	Northwestern Montana	Idaho Power Company	SFP
26	Morgan Stanley Capital Group	Northwestern Montana	Grant County PUD	SFP
27	Morgan Stanley Capital Group	Grant County PUD	Northwestern Montana	SFP
28	Morgan Stanley Capital Group	Chelan County PUD	Northwestern Montana	SFP
29	Puget Sound Energy	Northwestern Montana	Bonneville Power Administration	SFP
30	Tenaska	Northwestern Montana	Bonneville Power Administration	SFP
31	Pacificorp	Pacificorp	Idaho Power Company	SFP
32	Idaho Power Company LSE	Avista Corporation	Bonneville Power Administration	SFP
33	Idaho Power Company LSE	Avista Corporation	Idaho Power Company	SFP
34	Idaho Power Company LSE	Avista Corporation	Northwestern Montana	SFP
	TOTAL			

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2014	Year/Period of Report End of 2013/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
FERC No. 182	Dry Creek Walla Wall	Dry Gulch	20	60,578	60,578	1
FERC Trf No. 8	Chelan-Stratford 115	Stratford 115kV SS		238,507	238,507	2
FERC Trf No. 8	Chelan-Stratford 115	Stratford 115kV SS		238,507	238,507	3
FERC No. 104	Stratford Substation	Coulee Cy/Wilson Crk	25	89,976	89,976	4
FERC Trf No. 8	Westside	Little Falls	1	3,486	3,486	5
FERC Trf No. 8	Bell Substation	Post Falls	3	4,234	4,234	6
FERC Trf No. 8	Bell Substation	BKR/OPT/EFM/LIB	3	6,046	6,046	7
FERC Trf No. 8				1,869,693	1,869,693	8
FERC No. 155	Sunset-Westside 115k	Westside				9
FERC Trf No. 8	AVA Syst	AVA Syst				10
FERC Trf No. 8						11
FERC Trf No. 8						12
FERC Trf No. 8						13
FERC Trf No. 8						14
FERC Trf No. 8				12,816	12,816	15
FERC Trf No. 8				28,831	28,831	16
FERC Trf No. 8				3,324	3,324	17
FERC Trf No. 8				528	528	18
FERC Trf No. 8				400	400	19
FERC Trf No. 8				1,400	1,400	20
FERC Trf No. 8				762	762	21
FERC Trf No. 8				331	331	22
FERC Trf No. 8				2,565	2,565	23
FERC Trf No. 8				8,402	8,402	24
FERC Trf No. 8				171	171	25
FERC Trf No. 8				10	10	26
FERC Trf No. 8				25,454	25,454	27
FERC Trf No. 8				144	144	28
FERC Trf No. 8				1,680	1,680	29
FERC Trf No. 8				400	400	30
FERC Trf No. 8				3,348	3,348	31
FERC Trf No. 8				6,564	6,564	32
FERC Trf No. 8				30,936	30,936	33
FERC Trf No. 8				275	275	34
			52	**2,977,704**	**2,977,704**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
213,342			213,342	1
146,619		37,116	183,735	2
146,619		37,116	183,735	3
26,918			26,918	4
31,182			31,182	5
16,517			16,517	6
38,837			38,837	7
6,835,775			6,835,775	8
		27,973	27,973	9
		9,480	9,480	10
		6,120	6,120	11
		200,000	200,000	12
		402	402	13
		14,884,000	14,884,000	14
56,964			56,964	15
94,882			94,882	16
25,290			25,290	17
6,092			6,092	18
4,615			4,615	19
4,615			4,615	20
14,732			14,732	21
4,803			4,803	22
45,564			45,564	23
134,321			134,321	24
2,924			2,924	25
145			145	26
466,795			466,795	27
2,715			2,715	28
6,461			6,461	29
2,308			2,308	30
38,766			38,766	31
26,178			26,178	32
103,972			103,972	33
923			923	34
10,184,046	**0**	**15,202,207**	**25,386,253**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Idaho Power Company LSE	Bonneville Power Administration	Idaho Power Company	SFP
2	Idaho Power Company LSE	Bonneville Power Administration	Northwestern Montana	SFP
3	Idaho Power Company LSE	Pacificorp	Idaho Power Company	SFP
4	Idaho Power Company LSE	Idaho Power Company	Bonneville Power Administration	SFP
5	Idaho Power Company LSE	Chelan County PUD	Idaho Power Company	SFP
6	Coral Power	Avista Corporation	Chelan County PUD	NF
7	Coral Power	Avista Corporation	Grant County PUD	NF
8	Coral Power	Bonneville Power Administration	Idaho Power Company	NF
9	Coral Power	Bonneville Power Administration	Northwestern Montana	NF
10	Coral Power	Northwestern Montana	Avista Corporation	NF
11	Coral Power	Northwestern Montana	Bonneville Power Administration	NF
12	Coral Power	Northwestern Montana	Grant County PUD	NF
13	Coral Power	Northwestern Montana	Pacificorp	NF
14	Cargill Power Markets	Avista Corporation	Northwestern Montana	NF
15	Cargill Power Markets	Bonneville Power Administration	Idaho Power Company	NF
16	Cargill Power Markets	Northwestern Montana	Idaho Power Company	NF
17	Cargill Power Markets	Idaho Power Company	Bonneville Power Administration	NF
18	PPL Energy Plus	Bonneville Power Administration	Idaho Power Company	NF
19	PPL Energy Plus	Northwestern Montana	Bonneville Power Administration	NF
20	PPL Energy Plus	Northwestern Montana	Idaho Power Company	NF
21	Morgan Stanley Capital Group	Bonneville Power Administration	Idaho Power Company	NF
22	Morgan Stanley Capital Group	Bonneville Power Administration	Northwestern Montana	NF
23	Morgan Stanley Capital Group	Northwestern Montana	Bonneville Power Administration	NF
24	Morgan Stanley Capital Group	Northwestern Montana	Idaho Power Company	NF
25	Morgan Stanley Capital Group	Northwestern Montana	Grant County PUD	NF
26	Norwestern Energy	Northwestern Montana	Bonneville Power Administration	NF
27	PPM Energy Inc.	Avista Corporation	Bonneville Power Administration	NF
28	PPM Energy Inc.	Bonneville Power Administration	Idaho Power Company	NF
29	PPM Energy Inc.	Northwestern Montana	Bonneville Power Administration	NF
30	Puget Sound Energy	Bonneville Power Administration	Idaho Power Company	NF
31	Puget Sound Energy	Northwestern Montana	Bonneville Power Administration	NF
32	Puget Sound Energy	Puget Sound Energy	Idaho Power Company	NF
33	Powerex	Bonneville Power Administration	Idaho Power Company	NF
34	Powerex	Bonneville Power Administration	Northwestern Montana	NF
	TOTAL			

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
FERC Trf No. 8				229,164	229,164	1
FERC Trf No. 8				400	400	2
FERC Trf No. 8				1,624	1,624	3
FERC Trf No. 8				6	6	4
FERC Trf No. 8				3,904	3,904	5
FERC Trf No. 8				26	26	6
FERC Trf No. 8				105	105	7
FERC Trf No. 8				12,549	12,549	8
FERC Trf No. 8				195	195	9
FERC Trf No. 8						10
FERC Trf No. 8				735	735	11
FERC Trf No. 8				25	25	12
FERC Trf No. 8				140	140	13
FERC Trf No. 8				55	55	14
FERC Trf No. 8				424	424	15
FERC Trf No. 8				15	15	16
FERC Trf No. 8				200	200	17
FERC Trf No. 8				1,170	1,170	18
FERC Trf No. 8				125	125	19
FERC Trf No. 8				900	900	20
FERC Trf No. 8				820	820	21
FERC Trf No. 8				40	40	22
FERC Trf No. 8				4,253	4,253	23
FERC Trf No. 8				174	174	24
FERC Trf No. 8				14	14	25
FERC Trf No. 8				365	365	26
FERC Trf No. 8				286	286	27
FERC Trf No. 8				280	280	28
FERC Trf No. 8				162	162	29
FERC Trf No. 8				100	100	30
FERC Trf No. 8				1,450	1,450	31
FERC Trf No. 8				530	530	32
FERC Trf No. 8				949	949	33
FERC Trf No. 8				8	8	34
			52	**2,977,704**	**2,977,704**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2014	Year/Period of Report End of 2013/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
893,314			893,314	1
1,958			1,958	2
7,951			7,951	3
35			35	4
15,091			15,091	5
155			155	6
624			624	7
53,419			53,419	8
816			816	9
231			231	10
4,287			4,287	11
144			144	12
808			808	13
3,164			3,164	14
5,467			5,467	15
87			87	16
2,308			2,308	17
6,777			6,777	18
723			723	19
5,194			5,194	20
6,863			6,863	21
413			413	22
35,850			35,850	23
1,556			1,556	24
180			180	25
2,106			2,106	26
1,650			1,650	27
1,616			1,616	28
935			935	29
577			577	30
6,750			6,750	31
3,058			3,058	32
8,636			8,636	33
54			54	34
10,184,046	0	**15,202,207**	**25,386,253**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2014	Year/Period of Report End of 2013/Q4

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Powerex	Northwest Montana	Bonneville Power Administration	NF
2	Sierra Pacific Power Company	Bonneville Power Administration	Idaho Power Company	NF
3	Sierra Pacific Power Company	Portland General Electric	Idaho Power Company	NF
4	Transalta Energy Marketing	Bonneville Power Administration	Idaho Power Company	NF
5	Tenaska Power Services	Bonneville Power Administration	Avista Corporation	NF
6	Pacificorp	Pacificorp	Bonneville Power Administration	NF
7	Pacificorp	Pacificrop	Idaho Power Company	NF
8	Pacificorp	Idaho Power Company	Bonneville Power Administration	NF
9	Grant County PUD	Avista Corporation	Grant County PUD	NF
10	Bonneville Power Administration	Bonneville Power Administration	Idaho Power Company	NF
11	Portland General Electric	Northwestern Montana	Bonneville Power Administration	NF
12	Portland General Electric	Northwestern Montana	Portland General Electric	NF
13	Idaho Power Company	Bonneville Power Administration	Idaho Power Company	NF
14	Idaho Power Company	Idaho Power Company	Bonneville Power Administration	NF
15	Idaho Power Company LSE	Bonneville Power Administration	Idaho Power Company	NF
16	Idaho Power Company LSE	Bonneville Power Administration	Northwestern Montana	NF
17				
18				
19				
20				
21				
22				
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26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
FERC Trf No. 8				769	769	1
FERC Trf No. 8				1,125	1,125	2
FERC Trf No. 8				200	200	3
FERC Trf No. 8				125	125	4
FERC Trf No. 8				75	75	5
FERC Trf No. 8				3,740	3,740	6
FERC Trf No. 8				13,147	13,147	7
FERC Trf No. 8						8
FERC Trf No. 8						9
FERC Trf No. 8				26,869	26,869	10
FERC Trf No. 8				792	792	11
FERC Trf No. 8				175	175	12
FERC Trf No. 8				200	200	13
FERC Trf No. 8				1,374	1,374	14
FERC Trf No. 8				27,499	27,499	15
FERC Trf No. 8				1,053	1,053	16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			52	**2,977,704**	**2,977,704**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
4,437			4,437	1
6,712			6,712	2
1,222			1,222	3
721			721	4
577			577	5
45,835			45,835	6
171,714			171,714	7
1,154			1,154	8
1,800			1,800	9
170,902			170,902	10
4,951			4,951	11
1,010			1,010	12
1,154			1,154	13
7,928			7,928	14
183,175			183,175	15
9,083			9,083	16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
10,184,046	**0**	**15,202,207**	**25,386,253**	

Schedule Page: 328 Line No.: 2 Column: m

Use of facilities

Schedule Page: 328 Line No.: 3 Column: m

Use of facilities

Schedule Page: 328 Line No.: 9 Column: m

Use of facilities

Schedule Page: 328 Line No.: 10 Column: m

Use of facilities

Schedule Page: 328 Line No.: 11 Column: m

Use of facilities

Schedule Page: 328 Line No.: 12 Column: m

Deferral fee for long term firm service agreement

Schedule Page: 328 Line No.: 13 Column: m

Use of facilities

Schedule Page: 328 Line No.: 14 Column: m

Parallel Capacity Support Agreement

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2014	Year/Period of Report End of 2013/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Bonneville Power Admin	LFP			1,501,980			1,501,980
2	Bonneville Power Admin	LFP			11,462,622		1,865,364	13,327,986
3	Bonneville Power Admin	LFP			788,748			788,748
4	Bonneville Power Admin	OS					24,360	24,360
5	Bonneville Power Admin	FNS			1,046,774		148,550	1,195,324
6	Bonneville Power Admin	NF	21,225	21,225		91,904		91,904
7	Benton County PUD No. 1	NF	506	506		667		667
8	Clark County PUD No. 1	NF	1,328	1,328		1,992		1,992
9	Grays Harbor County PUD	NF	72	72		108		108
10	Kootenai Electric Coop	LFP			45,222			45,222
11	Northern Lights	LFP			133,517			133,517
12	NorthWestern Energy	SFP			58,496		5,450	63,946
13	NorthWestern Energy	NF	11,457	11,457		49,609		49,609
14	Portland General Elec	LFP			628,000		14,989	642,989
15	Portland General Elec	NF	13,659	13,659		19,062		19,062
16	Puget Sound Energy	NF	5,011	5,011		6,088		6,088
	TOTAL		78,716	78,716	15,665,359	202,829	2,058,713	17,926,901

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Seattle City Light	NF	23,532	23,532		30,958		30,958
2	Tacoma Power	NF	1,926	1,926		2,441		2,441
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		78,716	78,716	15,665,359	202,829	2,058,713	17,926,901

Schedule Page: 332 Line No.: 2 Column: g

Ancillary Services

Schedule Page: 332 Line No.: 4 Column: g

Use of Facilities

Schedule Page: 332 Line No.: 5 Column: g

Ancillary Services

Schedule Page: 332 Line No.: 12 Column: g

Ancillary Services

Schedule Page: 332 Line No.: 14 Column: g

Ancillary Services

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	550,799
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	317,333
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Community Relations	32,926
7	Director Fees and Expenses	921,955
8	Educational and Informational Expenses	9,034
9	Rating Agency Fees	184,482
10	Aircraft Operations and Fees	189,441
11	Other Miscellaneous General Expenses	902,337
12		
13		
14		
15		
16		
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19		
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22		
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45		
46	TOTAL	3,108,307

Schedule Page: 335 Line No.: 11 Column: b

Other miscellaneous general expenses, detail:

VENDOR	PURPOSE	AMOUNT
Various vendors < $5,000	Miscellaneous	$509,262
3BL Media LLC	Professional services	10,852
Adventures in Advertising	Miscellaneous	7,511
Bank of New York Mellon	Miscellaneous	15,047
Citibank NA	Miscellaneous	50,798
Coates Kokes	Professional services	6,511
Coeur d'Alene Resort	Miscellaneous	16,022
Corporate Credit Card	Miscellaneous	35,640
Davis Hibbitts & Midghall Inc	Professional services	21,342
Desautel Hege Communications	Professional services	16,951
Hanna & Associates	Professional services	40,080
HP Enterprise Solutions	Workforce contract	8,558
Jason R Thackston	Employee misc expenses	5,768
Klundt Hosmer Design	Professional services	36,725
Michael G Andrea	Employee misc expenses	7,616
Olsten	Workforce contract	15,670
Pure Works Inc	Professional services	33,267
Ricoh USA Inc	Miscellaneous	10,207
The Davenport Hotel	Miscellaneous	21,059
Union Bank of California	Miscellaneous	26,768
West Publishing Practical Company	Subscriptions	6,684

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			1,680,847		1,680,847
2	Steam Production Plant	7,661,394				7,661,394
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	8,053,492				8,053,492
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	9,211,859			2,450,031	11,661,890
7	Transmission Plant	10,014,786				10,014,786
8	Distribution Plant	35,524,899				35,524,899
9	Regional Transmission and Market Operation					
10	General Plant	3,559,209				3,559,209
11	Common Plant-Electric	10,605,806		6,648,082		17,253,888
12	TOTAL	84,631,445		8,328,929	2,450,031	95,410,405

B. Basis for Amortization Charges

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	STEAM PLANT						
13	Colstrip No. 3						
14	311	51,120	70.00	-10.00	1.56	S1.5	22.10
15	312	78,527	60.00	-10.00	1.93	R1	21.50
16	313	3					
17	314	23,956	40.00	-5.00	2.79	R0.5	19.40
18	315	9,550	50.00		1.73	R3	21.00
19	316	9,232	53.00		1.46	R2	20.90
20	Subtotal	172,388					
21							
22	Colstrip No. 4						
23	311	51,257	70.00	-10.00	1.68	S1.5	23.90
24	312	52,648	60.00	-10.00	2.20	R1	23.30
25	313	3					
26	314	15,676	40.00	-5.00	2.88	R0.5	20.90
27	315	6,699	50.00		1.88	R3	22.90
28	316	4,517	53.00		1.62	R2	22.70
29	Subtotal	130,800					
30							
31	Kettle Falls					0	
32	310	148			1.45	SQ	18.00
33	311	25,051	70.00	-10.00	1.51	S1.5	17.10
34	312	42,429	60.00	-10.00	1.93	R1	16.70
35	314	13,345	40.00	-5.00	2.12	R0.5	14.90
36	315	10,315	50.00		1.56	R3	16.40
37	316	2,612	53.00		1.74	R2	16.80
38	Subtotal	93,900					
39							
40	HYDRO PLANT						
41	Cabinet Gorge						
42	330	7,842	100.00		2.00	R4	43.20
43	331	12,163	110.00	-20.00	1.50	R2	51.50
44	332	31,936	100.00		1.13	R1	47.70
45	333	37,880	65.00	-10.00	2.04	R1.5	43.90
46	334	5,605	38.00	-5.00	2.97	R2.5	19.70
47	335	4,503	65.00		0.38	R1.5	49.90
48	336	1,099	55.00		1.96	S2	19.00
49	Subtotal	101,028					
50							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Noxon Rapids						
13	330	30,406	100.00		1.80	R4	48.80
14	331	15,226	110.00	-20.00	1.48	R2	58.40
15	332	33,811	100.00		1.12	R1	52.60
16	333	88,323	65.00	-10.00	1.98	R1.5	47.50
17	334	14,314	38.00	-5.00	2.79	R2.5	29.50
18	335	3,378	65.00		0.80	R1.5	53.60
19	336	247	55.00		1.89	S2	32.00
20	Subtotal	185,705					
21							
22	Post Falls						
23	330	2,908	75.00		2.81	R3	25.20
24	331	1,487	110.00	-20.00	2.09	R2	45.60
25	332	11,853	100.00		1.71	R1	44.70
26	333	2,234	65.00	-10.00	2.42	R1.5	29.60
27	334	719	38.00	-5.00	2.78	R2.5	18.20
28	335	223	65.00		1.15	R1.5	42.10
29	Subtotal	19,424					
30							
31	Long Lake						
32	330	418	75.00		4.42	R3	11.00
33	331	2,715	110.00	-20.00	1.99	R2	38.90
34	332	17,476	100.00		1.65	R1	40.00
35	333	8,824	65.00	-10.00	2.46	R1.5	33.30
36	334	2,823	38.00	-5.00	2.63	R2.5	22.50
37	335	542	65.00		1.22	R1.5	39.40
38	Subtotal	32,798					
39							
40	Little Falls						
41	330	4,217	100.00		3.35	R4	24.40
42	331	1,082	110.00	-20.00	1.94	R2	42.30
43	332	5,059	100.00		1.72	R1	43.60
44	333	3,939	65.00	-10.00	2.40	R1.5	33.60
45	334	5,137	38.00	-5.00	2.74	R2.5	22.20
46	335	134	65.00		0.69	R1.5	40.60
47	Subtotal	19,568					
48							
49	Upper Falls						
50	330	64	100.00		3.66	R4	22.20

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	331	962	110.00	-20.00	1.77	R2	41.40
13	332	7,674	100.00		1.85	R1	45.20
14	333	1,186	65.00	-10.00	2.53	R1.5	30.00
15	334	4,268	38.00	-5.00	2.81	R2.5	35.10
16	335	107	65.00		1.05	R1.5	41.20
17	336	320	55.00		1.94	S2	26.20
18	Subtotal	14,581					
19							
20	Nine Mile						
21	330	11	100.00		2.48	R4	35.90
22	331	4,302	110.00	-20.00	1.98	R2	46.50
23	332	13,653	100.00		1.83	R1	45.10
24	333	9,559	65.00	-10.00	2.17	R1.5	40.30
25	334	2,745	38.00	-5.00	2.80	R2.5	22.50
26	335	301	65.00		0.88	R1.5	41.20
27	336	625	55.00		1.93	S2	36.20
28	Subtotal	31,196					
29							
30	Monroe Street						
31	331	8,444	110.00	-20.00	1.71	R2	56.90
32	332	9,978	100.00		1.39	R1	53.20
33	333	11,031	65.00	-10.00	1.95	R1.5	45.50
34	334	1,685	38.00	-5.00	2.82	R2.5	23.40
35	335	34	65.00		1.19	R1.5	48.30
36	336	50	55.00		1.86	S2	36.60
37	Subtotal	31,222					
38							
39	OTHER PRODUCTION						
40	Northeast Turbine						
41	341	744	55.00		1.64	S4	8.00
42	342	31	55.00	-10.00	2.93	R3	8.00
43	343	9,058	55.00		0.81	S2.5	8.00
44	344	2,605	45.00		2.50	R1	7.40
45	345	1,237	20.00	-5.00	12.49	S2	7.90
46	346	407	35.00		2.51	R3	7.80
47	Subtotal	14,082					
48							
49	Rathdrum Turbine						
50	341	3,441	55.00		3.12	S4	24.00

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	342	1,696	55.00	-10.00	3.57	R3	23.50
13	343	5,722	55.00		2.77	S2.5	23.50
14	344	48,852	45.00		3.77	R1	21.60
15	345	2,929	20.00	-5.00	5.89	S2	15.20
16	346	115	35.00		2.51	R3	7.80
17	Subtotal	62,755					
18							
19	Kettle Falls CT						
20	342	89	55.00	-10.00	3.66	R3	17.70
21	343	9,071	55.00		3.24	S2.5	17.80
22	344	4	45.00		4.09	R1	16.60
23	345	14	20.00	-5.00	6.68	S2	11.40
24	Subtotal	9,178					
25							
26	Boulder Park						
27	341	1,205	55.00		2.54	S4	31.90
28	342	116	55.00	-10.00	2.62	R3	30.40
29	343	57	55.00		2.52	S2.5	30.90
30	344	30,611	45.00		2.94	R1	26.90
31	345	643	20.00	-5.00	6.03	S2	14.30
32	346	18	35.00		2.87	R3	26.20
33	Subtotal	32,650					
34							
35	Coyote Springs 2						
36	341	11,376	55.00		2.34	S4	32.80
37	342	19,150	55.00	-10.00	2.72	R3	31.40
38	344	125,422	45.00		3.00	R1	27.90
39	345	15,489	20.00	-5.00	6.14	S2	13.40
40	346	954	35.00		2.95	R3	27.40
41	Subtotal	172,391					
42							
43	Solar Power	183	25.00		5.30	S2.5	17.90
44	Subtotal	183					
45							
46	Lancaster						
47	342	92	55.00	-10.00	3.67	R3	29.40
48	344	209	45.00		3.70	R1	26.60
49	Subtotal	301					
50							

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	TRANSMISSION PLANT						
13	350	16,978	75.00		1.30	R4	56.80
14	352	19,294	60.00	-5.00	1.65	S2	48.00
15	353	220,820	45.00	-10.00	2.33	R2.5	33.10
16	354	17,125	70.00	-15.00	1.80	R4	41.00
17	355	163,845	65.00	-15.00	1.38	R2.5	54.70
18	356	120,208	65.00	-10.00	1.59	R2.5	50.20
19	357	2,838	60.00		1.64	R4	51.70
20	358	2,331	50.00		2.02	S2	35.40
21	359	1,950	65.00		1.66	R4	39.70
22	Subtotal	565,389					
23							
24	DISTRIBUTION PLANT						
25	360	2,416	75.00		1.34	R4	74.40
26	361	18,203	60.00	-10.00	1.62	R2.5	47.30
27	362	115,922	45.00		1.97	R1.5	34.20
28	364	280,550	55.00	-25.00	2.31	R2.5	41.10
29	365	187,950	50.00	-20.00	2.82	R3	32.70
30	366	88,448	50.00	-25.00	2.71	S2	37.60
31	367	150,617	28.00	-20.00	5.63	S2	16.80
32	368	207,666	44.00	-5.00	2.11	R2	33.00
33	369	137,574	55.00	-40.00	2.70	R4	37.55
34	370.2 - ID	21,447	15.00		7.65	S2.5	12.50
35	370.3 - WA	26,511	35.00		3.39	S0.5	23.60
36	373	16,962	35.00	-25.00	1.91	R2.5	26.45
37	373.4	22,165	35.00	-25.00	3.48	R2.5	26.80
38	Subtotal	1,276,431					
39							
40	GENERAL PLANT						
41	390.1	6,780	48.00	-5.00	1.67	S2	39.00
42	391.1	8,081	5.00		21.28	SQ	3.30
43	393	395	25.00		4.58	SQ	19.40
44	394	3,015	20.00		4.78	SQ	10.20
45	395	715	15.00		13.73	SQ	4.00
46	397	52,859	15.00		2.81	SQ	11.70
47	398	57	10.00		13.31	SQ	7.00
48	Subtotal	71,902					
49							
50	MISC POWER						

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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	392	3,815	15.00	20.00	1.83	L2.5	13.70
13	396	3,262	16.00	5.00	5.79	S0.5	11.80
14	Subtotal	7,077					
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25	TOTAL COMPANY	3,044,949					
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Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2014	Year/Period of Report End of 2013/Q4

REGULATORY COMMISSION EXPENSES

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

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 Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Federal Energy Regulatory Commission				
2	Charges include annual fee and license fees				
3	for the Spokane River Project, the Cabinet				
4	Gorge Project and the Noxon Rapids Project.	2,451,578	148,440	2,600,018	
5					
6					
7					
8					
9	Washington Utilities and Transportation				
10	Commission: includes annual fee and various				
11	other electric dockets	957,405	343,829	1,301,234	
12					
13	Includes annual fee and various other natural				
14	gas dockets	293,547	139,544	433,091	
15					
16	Idaho Public Utilities Commission				
17	Includes annual fee and various other electric				
18	dockets	573,860	227,806	801,666	
19					
20	Includes annual fee and various other natural				
21	gas dockets	144,134	95,022	239,156	
22					
23	Public Utility Commission of Oregon				
24	Includes annual fees and various other natural				
25	gas dockets	492,558	658,226	1,150,784	
26					
27	Not directly assigned electric		1,135,947	1,135,947	
28	Not directly assigned natural gas		433,989	433,989	
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	4,913,082	3,182,803	8,095,885	

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REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO			Deferred to Account 182.3	Contra Account	Amount	Deferred in Account 182.3 End of Year	Line No.
Department (f)	Account No. (g)	Amount (h)	(i)	(j)	(k)	(l)	
							1
							2
							3
Electric	928	2,600,018					4
							5
							6
							7
							8
							9
							10
Electric	928	1,301,234					11
							12
							13
Gas	928	433,091					14
							15
							16
							17
Electric	928	801,666					18
							19
							20
Gas	928	239,156					21
							22
							23
							24
Gas	928	1,150,784					25
							26
Electric	928	1,134,947					27
Gas	928	433,989					28
							29
							30
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							45
		8,094,885					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

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

Classifications:

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

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	A 3 Electric - Distribution	Smart Grid Demonstration Grant (Meters)
2		
3		
4		
5		
6		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

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

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
712,431	652,076	107	1,364,507		1
-688		108	-688		2
28,927		580	28,927		3
5,906	3,526	587	9,432		4
2,011	77,850	588	79,861		5
98,939		920	98,939		6
63,235	45,272	921	108,507		7
3,850	97,434	923	101,284		8
830	132,894	935	133,724		9
					10
					11
					12
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DISTRIBUTION OF SALARIES AND WAGES

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

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	9,813,365		
4	Transmission	2,873,835		
5	Regional Market			
6	Distribution	6,807,675		
7	Customer Accounts	6,785,677		
8	Customer Service and Informational	673,333		
9	Sales	4,691		
10	Administrative and General	19,780,951		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	46,739,527		
12	Maintenance			
13	Production	3,199,050		
14	Transmission	1,032,292		
15	Regional Market			
16	Distribution	4,110,260		
17	Administrative and General			
18	TOTAL Maintenance (Total of lines 13 thru 17)	8,341,602		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	13,012,415		
21	Transmission (Enter Total of lines 4 and 14)	3,906,127		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	10,917,935		
24	Customer Accounts (Transcribe from line 7)	6,785,677		
25	Customer Service and Informational (Transcribe from line 8)	673,333		
26	Sales (Transcribe from line 9)	4,691		
27	Administrative and General (Enter Total of lines 10 and 17)	19,780,951		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	55,081,129	12,214,215	67,295,344
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply	760,859		
34	Storage, LNG Terminaling and Processing	10,989		
35	Transmission			
36	Distribution	3,829,256		
37	Customer Accounts	2,641,267		
38	Customer Service and Informational	304,692		
39	Sales	1,230		
40	Administrative and General	7,385,882		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	14,934,175		
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission	1,046,252		

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DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	2,819,587		
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	3,865,839		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)	760,859		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	10,989		
56	Transmission (Lines 35 and 47)	1,046,252		
57	Distribution (Lines 36 and 48)	6,648,843		
58	Customer Accounts (Line 37)	2,641,267		
59	Customer Service and Informational (Line 38)	304,692		
60	Sales (Line 39)	1,230		
61	Administrative and General (Lines 40 and 49)	7,385,882		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	18,800,014	4,193,954	22,993,968
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	73,881,143	16,408,169	90,289,312
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	23,565,517	4,494,568	28,060,085
69	Gas Plant	6,314,473	1,718,033	8,032,506
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	29,879,990	6,212,601	36,092,591
72	Plant Removal (By Utility Departments)			
73	Electric Plant	1,958,817	5,786,393	7,745,210
74	Gas Plant	81,433	1,623,519	1,704,952
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	2,040,250	7,409,912	9,450,162
77	Other Accounts (Specify, provide details in footnote):			
78	Stores Expense (163)	1,959,483	-1,959,483	
79	Preliminary Survey and Investigation (183)	-16,331		-16,331
80	Small Tool Expense	3,367,904	-3,367,904	
81	Miscellaneous Deferred Debits (186)	2,685,152		2,685,152
82	Non-operating Expenses (417)	597,199		597,199
83	Activities (426)	973,187		973,187
84	Employee Incentive Plan (232380)	8,098,154	-8,098,154	
85	DSM Tariff Rider and Payroll Equialization Liability (242600,	18,486,730	-16,676,525	1,810,205
86	Incentive / Stock Compensation (238000)	123,259		123,259
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	36,274,737	-30,102,066	6,172,671
96	TOTAL SALARIES AND WAGES	142,076,120	-71,384	142,004,736

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

COMMON UTILITY PLANT AND EXPENSES

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

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

Acct. No.	Description	
303	Intangible	60,228,801
389	Land and Land Rights	5,145,059
390	Structures and Improvements	99,193,217
391	Office Furniture and Equipment	46,829,149
392	Transportation Equipment	10,756,983
393	Stores Equipment	2,480,142
394	Tools, Shop & Garage Equipment	9,273,499
395	Laboratory Equipment	463,078
396	Power Operated Equipment	2,074,594
397	Communications Equipment	33,619,657
398	Miscellaneous Equipment	461,883
399	Asset Retirement Cost	0
	Total Common Plant	270,526,062
	Const. Work in Progress	54,296,158
	Total Utility Plant	324,822,220
	Acc. Prov. for Dep. & Amort.	71,713,657
	Net Utility Plant	253,108,563

3. Common Expenses allocated to Electric and Gas departments:

Acct. No.	Description	Total	Allocation to Electric Dept	Allocated to Gas Dept	Basis of Allocation
901	Cust acct/collect supervision	669,271	353,964	315,307	#of cust @ yr end
902	Meter reading expenses	5,068,453	3,120,748	1,947,705	#of cust @ yr end
903	Cust rec and collection expenses	15,794,773	8,602,880	7,191,893	#of cust @ yr end
903.90-99	A/R misc fees	0	0	0	net direct plant
904	Uncollectible accounts	4,792,408	2,534,687	2,257,721	#of cust @ yr end
905	Misc cust acct expenses	449,363	237,659	211,704	#of cust @ yr end
907	Cust svce & Info exp supervision	0	0	0	#of cust @ yr end
908	Cust assistance expenses	1,039,624	640,062	399,562	#of cust @ yr end
909	Info & instruct expenses	1,690,037	1,029,751	660,286	#of cust @ yr end
910	Misc cust serv & info	380,071	201,012	179,059	#of cust @ yr end

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COMMON UTILITY PLANT AND EXPENSES

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

	expenses				
911	Sales expense -supervision	0	0	0	#of cust @ yr end
912	Demo & selling expenses	12,022	7,402	4,620	#of cust @ yr end
913	Advertising expenses	0	0	0	#of cust @ yr end
916	Misc sales expenses	0	0	0	#of cust @ yr end
920	Admin & gen salaries	32,171,136	23,363,682	8,807,454	four factor
921	Office supplies expenses	5,381,626	3,897,750	1,483,876	four factor
922	Admin expenses tranf-credit	0	0	0	four factor
923	Outside services employed	14,137,495	10,233,513	3,903,982	four factor
924	Property insurance	1,661,704	1,202,176	459,528	four factor
925	Injuries and damages	6,236,880	4,664,270	1,572,610	four factor
926	Employee pensions & benefits	68,053,926	49,279,119	18,774,807	four factor
927	Franchise requirement	0	0	0	four factor
928	Regulatory commission expenses	1,775,399	1,298,716	476,682	four factor
929	Duplicate charges-credit	0	0	0	four factor
930.1	General advertising expenses	148	117	31	four factor
930.2	Misc general expenses	3,346,310	2,446,159	900,151	four factor
931	Rents	1,067,504	785,666	281,838	four factor
935	Maint of general plant	10,389,580	7,650,051	2,739,529	four factor
403	Depreciation	14,550,888	10,605,806	3,954,082	four factor
404	Amort of LTD term plant	9,187,038	6,648,082	2,538,956	four factor

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	638	MW	146,836			
2	Reactive Supply and Voltage						
3	Regulation and Frequency Response	59,292	MW/h	7,538	73,212	MW	654,511
4	Energy Imbalance				621	MW	1,925,512
5	Operating Reserve - Spinning	308	MW/h	6,389	136,071	MW/h	1,408,999
6	Operating Reserve - Supplement	308	MW/h	6,389	11,125	MW/h	85,667
7	Other	1,337,514	MW	11,957,372	1,337,514	MW	11,957,372
8	Total (Lines 1 thru 7)	1,398,060		12,124,524	1,558,543		16,032,061

FOOTNOTE DATA

Schedule Page: 398 Line No.: 7 Column: b

Interdepartmental spinning reserve service for Native Load.

Schedule Page: 398 Line No.: 7 Column: d

Interdepartmental spinning reserve service for Native Load.

Schedule Page: 398 Line No.: 7 Column: e

Interdepartmental spinning reserve service for Native Load.

Schedule Page: 398 Line No.: 7 Column: g

Interdepartmental spinning reserve service for Native Load.

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	2,146	15	800	1,492	311	162	14	180	277
2	February	1,932	20	1900	1,390	260	162	15	120	418
3	March	1,970	5	1900	1,441	255	162	14	112	703
4	Total for Quarter 1	6,048			4,323	826	486	43	412	1,398
5	April	1,962	10	900	1,110	217	182	15	453	17
6	May	2,057	9	1700	1,258	223	185	19	391	218
7	June	2,271	28	1700	1,359	235	180	31	497	50
8	Total for Quarter 2	6,290			3,727	675	547	65	1,341	285
9	July	2,452	2	1700	1,582	294	181	30	395	87
10	August	2,315	15	1700	1,461	266	180	30	409	94
11	September	1,921	11	1700	1,385	240	178	25	118	35
12	Total for Quarter 3	6,688			4,428	800	539	85	922	216
13	October	1,855	30	800	1,295	271	168	18	121	261
14	November	2,046	21	800	1,403	310	162	16	171	118
15	December	2,353	8	1800	1,652	368	162	19	171	363
16	Total for Quarter 4	6,254			4,350	949	492	53	463	742
17	Total Year to Date/Year	25,280			16,828	3,250	2,064	246	3,138	2,641

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	8,909,409
3	Steam	1,521,530			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	
5	Hydro-Conventional	3,645,832			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	4,409,585
7	Other	1,861,743			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	7,029,105	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	12,202
10	Purchases	6,911,072	27	Total Energy Losses	606,456
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	13,937,652
12	Received	554,654			
13	Delivered	557,179			
14	Net Exchanges (Line 12 minus line 13)	-2,525			
15	Transmission For Other (Wheeling)				
16	Received	2,977,704			
17	Delivered	2,977,704			
18	Net Transmission for Other (Line 16 minus line 17)				
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	13,937,652			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

MONTHLY PEAKS AND OUTPUT

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

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	1,319,333	356,419	1,574	21	1800
30	February	1,256,836	457,520	1,408	21	1900
31	March	1,307,820	492,443	1,394	19	0800
32	April	1,346,675	606,125	1,284	23	0800
33	May	1,329,388	591,874	1,304	10	1700
34	June	1,142,424	424,485	1,406	28	1700
35	July	1,078,803	268,224	1,577	2	1700
36	August	1,000,408	213,044	1,473	14	1600
37	September	886,374	200,650	1,385	12	1700
38	October	989,947	261,232	1,271	30	0800
39	November	1,088,750	288,147	1,415	21	1800
40	December	1,190,894	249,422	1,669	8	1800
41	TOTAL	13,937,652	4,409,585			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Coyote Springs 2* (b)			Plant Name: *Spokane N.E.* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Not Applicable			Not Applicable		
3	Year Originally Constructed	2003			1978		
4	Year Last Unit was Installed	2003			1978		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	287.00			61.80		
6	Net Peak Demand on Plant - MW (60 minutes)	309			49		
7	Plant Hours Connected to Load	7316			5		
8	Net Continuous Plant Capability (Megawatts)	284			65		
9	When Not Limited by Condenser Water	284			0		
10	When Limited by Condenser Water	284			0		
11	Average Number of Employees	13			1		
12	Net Generation, Exclusive of Plant Use - KWh	1796280000			222000		
13	Cost of Plant: Land and Land Rights	0			157277		
14	Structures and Improvements	11376063			744320		
15	Equipment Costs	161014832			14071514		
16	Asset Retirement Costs	351682			0		
17	Total Cost	172742577			14973111		
18	Cost per KW of Installed Capacity (line 17/5) Including	601.8905			242.2833		
19	Production Expenses: Oper, Supv, & Engr	1296595			24213		
20	Fuel	56366668			13131		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	1719047			35644		
26	Misc Steam (or Nuclear) Power Expenses	186321			14935		
27	Rents	6695			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	813345			441		
30	Maintenance of Structures	45726			620		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	1368944			260556		
33	Maintenance of Misc Steam (or Nuclear) Plant	59263			31844		
34	Total Production Expenses	61862604			381384		
35	Expenses per Net KWh	0.0344			1.7179		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas			Gas		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF			MCF		
38	Quantity (Units) of Fuel Burned	12307078	0	0	3132	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1020000	0	0	1020000	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	4.580	0.000	0.000	4.192	0.000	0.000
41	Average Cost of Fuel per Unit Burned	4.580	0.000	0.000	4.192	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	4.490	0.000	0.000	4.110	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.031	0.000	0.000	0.059	0.000	0.000
44	Average BTU per KWh Net Generation	6988.000	0.000	0.000	14390.000	0.000	0.000

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2014	Year/Period of Report End of 2013/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Kettle Falls* (d)			Plant Name: *Colstrip* (e)			Plant Name: *Rathdrum* (f)			Line No.
		Steam			Steam			Gas Turbine	1
		Conventional			Conventional			Not Applicable	2
		1983			1984			1995	3
		1983			1985			1995	4
		50.70			233.40			166.50	5
		51			230			169	6
		7152			8532			255	7
		54			222			167	8
		54			222			0	9
		54			222			0	10
		25			145			1	11
		294379000			1227151000			33688000	12
		2200714			1289095			621682	13
		25050783			102377273			3441419	14
		68696179			200812917			59314059	15
		450687			134589			0	16
		96398363			304613874			63377160	17
		1901.3484			1305.1151			380.6436	18
		70260			211681			17129	19
		7916177			17275865			1473796	20
		0			0			0	21
		738364			3459834			0	22
		0			0			0	23
		0			0			0	24
		945687			72140			167520	25
		459098			2286638			170340	26
		0			33093			0	27
		0			0			0	28
		72162			366389			597	29
		59747			621023			969	30
		1704204			4396751			0	31
		325820			846926			191789	32
		228612			570742			17584	33
		12520131			30141082			2039724	34
		0.0425			0.0246			0.0605	35
Wood	Gas		Coal	Oil		Gas			36
TON	MCF		TON	BBL		MCF			37
478948	4047	0	768825	1648	0	3733240	0	0	38
8600000	1020000	0	16970000	5880000	0	1020000	0	0	39
16.492	4.269	0.000	22.179	135.940	0.000	4.216	0.000	0.000	40
16.492	4.269	0.000	22.179	135.940	0.000	4.216	0.000	0.000	41
1.920	4.186	0.000	1.307	23.120	0.000	4.133	0.000	0.000	42
0.027	0.055	0.000	0.014	0.000	0.000	0.044	0.000	0.000	43
14007.000	0.000	0.000	10640.000	0.000	0.000	10585.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Boulder Park* (b)	Plant Name: (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Internal Comb	
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	
3	Year Originally Constructed	2002	
4	Year Last Unit was Installed	2002	
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	24.60	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	25	0
7	Plant Hours Connected to Load	1228	0
8	Net Continuous Plant Capability (Megawatts)	24	0
9	When Not Limited by Condenser Water	0	0
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	1	0
12	Net Generation, Exclusive of Plant Use - KWh	25921000	0
13	Cost of Plant: Land and Land Rights	185629	0
14	Structures and Improvements	1204874	0
15	Equipment Costs	31444866	0
16	Asset Retirement Costs	0	0
17	Total Cost	32835369	0
18	Cost per KW of Installed Capacity (line 17/5) Including	1334.7711	0
19	Production Expenses: Oper, Supv, & Engr	11703	0
20	Fuel	1026805	0
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	156988	0
26	Misc Steam (or Nuclear) Power Expenses	39616	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	264	0
30	Maintenance of Structures	496	0
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	163441	0
33	Maintenance of Misc Steam (or Nuclear) Plant	66608	0
34	Total Production Expenses	1465921	0
35	Expenses per Net KWh	0.0566	0.0000

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas					
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF					
38	Quantity (Units) of Fuel Burned	237308	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1020000	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	4.327	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	4.327	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	4.242	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.040	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	9338.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

(d)			(e)			(f)			Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2014	Year/Period of Report End of 2013/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

									Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Schedule Page: 402 Line No.: -1 Column: b

Operated by Portland General Electric.

Schedule Page: 402 Line No.: -1 Column: c

designed for peak load service

Schedule Page: 403 Line No.: -1 Column: e

Joint project operated by PPL Montana LLC.

Schedule Page: 403 Line No.: -1 Column: f

designed for peak load service

Schedule Page: 402.1 Line No.: -1 Column: b

designed for peak load service

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 2545 Plant Name: Monroe Street (b)	FERC Licensed Project No. 2545 Plant Name: Upper Falls (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Run-of-River
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1890	1922
4	Year Last Unit was Installed	1992	1922
5	Total installed cap (Gen name plate Rating in MW)	14.80	10.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	17	12
7	Plant Hours Connect to Load	8,651	8,401
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	15	10
10	(b) Under the Most Adverse Oper Conditions	15	10
11	Average Number of Employees	4	4
12	Net Generation, Exclusive of Plant Use - Kwh	104,654,000	68,384,000
13	Cost of Plant		
14	Land and Land Rights	0	1,081,854
15	Structures and Improvements	8,443,779	962,432
16	Reservoirs, Dams, and Waterways	9,977,635	7,674,146
17	Equipment Costs	12,749,437	5,561,235
18	Roads, Railroads, and Bridges	50,448	320,283
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	31,221,299	15,599,950
21	Cost per KW of Installed Capacity (line 20 / 5)	2,109.5472	1,559.9950
22	Production Expenses		
23	Operation Supervision and Engineering	0	438
24	Water for Power	0	0
25	Hydraulic Expenses	0	36
26	Electric Expenses	604,700	595,859
27	Misc Hydraulic Power Generation Expenses	26,632	41,490
28	Rents	0	0
29	Maintenance Supervision and Engineering	145	40,403
30	Maintenance of Structures	2,258	623,254
31	Maintenance of Reservoirs, Dams, and Waterways	26,523	273,151
32	Maintenance of Electric Plant	48,731	104,916
33	Maintenance of Misc Hydraulic Plant	9,766	7,678
34	Total Production Expenses (total 23 thru 33)	718,755	1,687,225
35	Expenses per net KWh	0.0069	0.0247

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 2545 Plant Name: Nine Mile Falls (d)	FERC Licensed Project No. 2545 Plant Name: Post Falls (e)	FERC Licensed Project No. 2058 Plant Name: Cabinet Gorge (f)	Line No.
Run-of-River	Storage	Storage	1
Conventional	Conventional	Outdoor	2
1908	1906	1952	3
1994	1980	1953	4
26.40	14.80	265.00	5
19	19	269	6
8,132	7,003	8,409	7
			8
18	18	295	9
18	18	255	10
4	4	13	11
82,922,000	84,904,000	1,042,427,000	12
			13
33,429	3,570,115	11,550,027	14
3,957,442	1,486,719	12,163,276	15
13,652,590	11,852,726	31,936,304	16
12,604,124	3,175,578	47,987,742	17
625,181	0	1,098,564	18
0	0	0	19
30,872,766	20,085,138	104,735,913	20
1,169.4230	1,357.1039	395.2299	21
			22
17,269	4,625	107,196	23
0	0	0	24
6,393	0	7,195	25
652,106	656,380	1,271,430	26
50,141	51,914	188,001	27
0	0	0	28
3,296	235	14,481	29
32,504	11,144	117,552	30
51,021	52,293	32,608	31
258,814	263,380	338,352	32
6,604	1,766	39,313	33
1,078,148	1,041,737	2,116,128	34
0.0130	0.0123	0.0020	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 2058 Plant Name: Noxon Rapids (b)	FERC Licensed Project No. 2545 Plant Name: Long Lake (c)
1	Kind of Plant (Run-of-River or Storage)	Storage	Storage
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional
3	Year Originally Constructed	1959	1915
4	Year Last Unit was Installed	1977	1924
5	Total installed cap (Gen name plate Rating in MW)	487.80	70.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	524	89
7	Plant Hours Connect to Load	4,936	6,585
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	622	90
10	(b) Under the Most Adverse Oper Conditions	581	90
11	Average Number of Employees	11	5
12	Net Generation, Exclusive of Plant Use - Kwh	1,581,223,000	504,779,000
13	Cost of Plant		
14	Land and Land Rights	35,630,883	2,089,177
15	Structures and Improvements	15,226,041	2,715,316
16	Reservoirs, Dams, and Waterways	33,810,811	17,475,672
17	Equipment Costs	106,014,530	12,188,460
18	Roads, Railroads, and Bridges	246,561	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	190,928,826	34,468,625
21	Cost per KW of Installed Capacity (line 20 / 5)	391.4080	492.4089
22	Production Expenses		
23	Operation Supervision and Engineering	117,823	28,080
24	Water for Power	0	0
25	Hydraulic Expenses	101,310	14,544
26	Electric Expenses	1,338,305	818,592
27	Misc Hydraulic Power Generation Expenses	152,695	58,753
28	Rents	0	0
29	Maintenance Supervision and Engineering	16,251	8,901
30	Maintenance of Structures	88,773	47,032
31	Maintenance of Reservoirs, Dams, and Waterways	132,546	1,093,190
32	Maintenance of Electric Plant	2,343,810	262,203
33	Maintenance of Misc Hydraulic Plant	111,136	38,465
34	Total Production Expenses (total 23 thru 33)	4,402,649	2,369,760
35	Expenses per net KWh	0.0028	0.0047

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 2545 Plant Name: Little Falls (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
Run-of-River			1
Conventional			2
1910			3
1911			4
32.00	0.00	0.00	5
36	0	0	6
6,651	0	0	7
			8
36	0	0	9
36	0	0	10
4	0	0	11
176,539,000	0	0	12
			13
4,325,371	0	0	14
1,081,881	0	0	15
5,058,551	0	0	16
9,209,759	0	0	17
0	0	0	18
0	0	0	19
19,675,562	0	0	20
614.8613	0.0000	0.0000	21
			22
22	0	0	23
0	0	0	24
10,475	0	0	25
628,565	0	0	26
20,217	0	0	27
810,477	0	0	28
3,256	0	0	29
42,207	0	0	30
68,135	0	0	31
202,527	0	0	32
5,421	0	0	33
1,791,302	0	0	34
0.0101	0.0000	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Kettle Falls CT	2002	7.20	8.0	5,632,000	9,178,263
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
1,274,759	124,033	282,782	27,366	Nat Gas	427	1
						2
						3
						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
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						20
						21
						22
						23
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						25
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						44
						45
						46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Group Sum		60.00	60.00		1.00		
2								
3	Group Sum		115.00	115.00		1,544.00		
4								
5	Beacon Sub #4	BPA Bell Sub	230.00	230.00	Steel Tower	1.00		1
6	Beacon Sub	BPA Bell Sub	230.00	230.00	H Type	5.00		1
7	Beacon Sub #5	BPA Bell Sub	230.00	230.00	Steel Pole	4.00		1
8	Beacon Sub #5	BPA Bell Sub	230.00	230.00	H Type	2.00		1
9	Beacon	Cabinet Gorge Plant	230.00	230.00	Steel Tower		1.00	1
10	Beacon	Cabinet Gorge Plant	230.00	230.00	Steel Pole	27.00		2
11	Beacon	Cabinet Gorge Plant	230.00	230.00	H Type	53.00		1
12	Beacon Sub	Lolo Sub	230.00	230.00	Steel Tower	1.00		1
13	Beacon Sub	Lolo Sub	230.00	230.00	H Type	102.00		1
14	Benewah	Shawnee	230.00	230.00	Steel Pole	60.00		1
15	Noxon Plant	Pine Creek Sub	230.00	230.00	Steel Pole	30.00		1
16	Noxon Plant	Pine Creek Sub	230.00	230.00	H Type	14.00		1
17	Cabinet Gorge Plant	Noxon	230.00	230.00	H Type	19.00		1
18	Benewah Sw. Station	Pine Creek Sub	230.00	230.00	Steel Tower			1
19	Benewah Sw. Station	Pine Creek Sub	230.00	230.00	H Type	43.00		1
20	Divide Creek	Lolo Sub	230.00	230.00	Steel Tower			1
21	Divide Creek	Lolo Sub	230.00	230.00	H Type	43.00		1
22	N. Lewiston	Walla Walla	230.00	230.00	H Type	43.00		1
23	N. Lewiston	Walla Walla	230.00	230.00	Steel Pole	4.00		1
24	N. Lewiston	Shawnee	230.00	230.00	Steel Pole	7.00		1
25	N. Lewiston	Shawnee	230.00	230.00	H Type	27.00		1
26	Walla Walla	Wanapum	230.00	230.00	Alum			1
27	Walla Walla	Wanapum	230.00	230.00	H Type	78.00		1
28	BPA (Libby)	Noxon Plant	230.00	230.00	Steel Tower	1.00		1
29	BPA/Hot Springs #1	Noxon Plant	230.00	230.00	Steel Tower	1.00		1
30	BPA/Hot Springs #2	Noxon Plant (dead)	230.00	230.00	Steel Tower		2.00	1
31	BPA/Hot Springs #2	Noxon Plant	230.00	230.00	H Type	68.00		1
32	BPA Line	West Side Sub	230.00	230.00	Steel Pole	2.00		2
33	Hatwai	N. Lewiston Sub	230.00	230.00	H Type	7.00		1
34	Divide Creek	Imnaha	230.00	230.00	H Type	20.00		1
35	Colstrip Plant	Broadview	500.00	500.00				
36					TOTAL	2,207.00	3.00	32

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
	136,038	498,430	634,468					1
								2
	10,156,257	130,753,980	140,910,237	154,571	699,498		854,069	3
								4
1272 ACSS								5
1272 ACSS	17,912	1,316,679	1,334,591	8,814	1,828		10,642	6
1272 ACSS								7
1272 ACSS	30,323	3,275,357	3,305,680		1,163		1,163	8
1272 ACSS								9
1590 ACSS								10
1590 ACSR	1,156,196	36,554,273	37,710,469	642	26,985		27,627	11
1272 ACSS								12
1272 McMAL	456,162	8,532,446	8,988,608	864	5,619		6,483	13
1590 ACSS	570,207	48,024,931	48,595,138	433	11,467		11,900	14
1272 ACSR								15
954 McMAL	1,097,679	18,087,788	19,185,467	2,620	259,691		262,311	16
954 McMAL	184,211	1,637,500	1,821,711	282	18,721		19,003	17
954 McMAL								18
954 McMAL	320,360	2,611,383	2,931,743	36,570	8,843		45,413	19
1272 McMAL								20
1272 McMAL	86,228	4,488,642	4,574,870	2,921	58,588		61,509	21
1272 McMAL								22
1272 McMAL	623,984	6,996,684	7,620,668	777	1,934		2,711	23
1272 ACSR								24
1272 ACSR	872,150	10,043,831	10,915,981	48	5,012		5,060	25
1272 McMAL								26
1272 McMAL	70,781	2,777,345	2,848,126	114,176	28,908		143,084	27
1272 ACSR								28
1272 ACSR		19,521	19,521	3,379	1,618		4,997	29
1272 McMAL								30
1272 McMAL	307,633	4,059,400	4,367,033	109,719	8,651		118,370	31
1272 ACSR	36,462	594,652	631,114		3,414		3,414	32
1590 ACSR	106,581	2,600,738	2,707,319		2,172		2,172	33
1272 McMAL	205,262	1,322,283	1,527,545	282			282	34
	595,789	30,535,854	31,131,643	40,078	248,565	89,844	378,487	35
	17,030,215	314,731,717	331,761,932	476,176	1,392,677	89,844	1,958,697	36

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2014	Year/Period of Report End of 2013/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)	(c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	No new transmission lines	added in 2013					
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
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20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL						

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage KV (Operating) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
									1
									2
									3
									4
									5
									6
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	STATE OF WASHINGTON				
2					
3	Airway Heights	Distr. Unattended	115.00	13.80	
4	Barker Road	Distr. Unattended	115.00	13.80	
5	Beacon	Trnsm. & Distr Unatt	230.00	115.00	13.80
6	Boulder	Trnsm. Unattended	230.00	115.00	13.80
7	Chester	Distr. Unattended	115.00	13.80	
8	Chewelah 115Kv	Distr. Unattended	115.00	13.80	
9	Colbert	Distr. Unattended	115.00	13.80	
10	College & Walnut	Distr. Unattended	115.00	13.80	
11	Colville 115Kv	Distr. Unattended	115.00	13.80	
12	Critchfield	Distr. Unattended	115.00	13.80	
13	Deer Park	Dist. Unattended	115.00	13.80	
14	Dry Creek	Transm. Unattended	230.00	115.00	13.80
15	Dry Gulch	Distr. Unattended	115.00	13.80	
16	East Colfax	Distr. Unattended	115.00	13.80	
17	East Farms	Distr. Unattended	115.00	13.80	
18	Fort Wright	Distr. Unattended	115.00	13.80	
19	Francis and Cedar	Distr. Unattended	115.00	13.80	
20	Gifford	Distr. Unattended	115.00	34.00	
21	Glenrose	Distr. Unattended	115.00	13.80	
22	Greenwood	Distr. Unattended	115.00	13.80	
23	Hallett & White	Distr. Unattended	115.00	13.80	
24	Indian Trail	Dist. Unattended	115.00	13.80	
25	Industrial Park	Dist. Unattended	115.00	13.80	
26	Kettle Falls	Distr. Unattended	115.00	13.80	
27	Lee & Reynolds	Distr. Unattended	115.00	13.80	
28	Liberty Lake	Distr. Unattended	115.00	13.80	
29	Little Falls 115/34Kv	Distr. Unattended	115.00	34.00	
30	Lyons & Standard	Distr. Unattended	115.00	13.80	
31	Mead	Distr. Unattended	115.00	13.80	
32	Metro	Distr. Unattended	115.00	13.80	
33	Milan	Distr. Unattended	115.00	13.80	
34	Millwood	Dist. Unattended	115.00	13.80	
35	Ninth & Central	Distr. Unattended	115.00	13.80	
36	Northeast	Distr. Unattended	115.00	13.80	
37	Northwest	Distr. Unattended	115.00	13.80	
38	Opportunity	Dist. Unattended	115.00	13.80	
39	Othello	Distr. Unattended	115.00	13.80	
40	Post Street	Distr. Unattended	115.00	13.80	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
						2
24	2		Frcd Oil&Air Fan&Cap	39	40	3
12	1		Two Stage Fan	1	20	4
536	4		Two Stage Fan	2	560	5
300	2		Two Stage Fan	2	500	6
24	2		Frcd Oil & Air Fan	2	40	7
12	1		Two Stage Fan	1	20	8
12	1		Frcd Oil & Air Fan	16	20	9
36	2		Two Stage Fan	2	60	10
32	3		Frcd Oil & Air Fan	3	45	11
12	1		Two Stage Fan	1	20	12
12	1		Two Stage Fan	1	20	13
150	1		Two Stage Fan & Caps	223	250	14
24	2		Frcd Oil & Air Fan	2	40	15
12	1		FrOil/Air Fan	1	20	16
12	1		Two Stage Fan	1	20	17
24	2	1	Fr Oil/Air/2StgFan	2	40	18
36	2		Two Stage Fan	2	60	19
12	1					20
12	1		Frcd Oil & Air Fan	1	20	21
12	1		Two Stage Fan	1	20	22
12	1		Two Stg Fan	1	20	23
12	1		Two Stage Fan	1	20	24
24	2		Two Stg/Pt/Frcd Oil	14	40	25
12	1		Frcd Oil & Air Fan	1	20	26
12	1		Two Stage Fan	1	20	27
24	2		Two Stage Fan	2	40	28
12	1					29
36	2		Two Stage Fan	2	60	30
18	1		Two Stage Fan	1	30	31
24	2		Two Stage Fan	2	40	32
24	2		Frcd Oil & Air Fan	2	40	33
24	2	2	Two Stage Fan	2	40	34
24	2	1	Frcd & Two Stage Fan	2	40	35
24	2		Two Stage Fan	2	40	36
24	2		Two Stage Fan	2	40	37
12	1		Two Stage Fan	1	20	38
24	2		FrOil/AirFan	2	40	39
36	2		Frcd Oil & Wt Fan	2	60	40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Pound Lane	Distr. Unattended	115.00	13.80	
2	Ross Park	Distr. Unattended	115.00	13.80	
3	Roxboro	Distr. Unattended	115.00	24.00	
4	Shawnee	Trans. Unattended	230.00	115.00	13.80
5	Silver Lake	Distr. Unattended	115.00	13.80	
6	Southeast	Distr. Unattended	115.00	13.80	
7	South Othello	Distr. Unattended	115.00	13.80	
8	South Pullman	Distr. Unattended	115.00	13.80	
9	Sunset	Distr. Unattended	115.00	13.80	
10	Terre View	Dist. Unattended	115.00	13.80	
11	Third & Hatch	Distr. Unattended	115.00	13.80	
12	Turner	Dist. Unattended	115.00	13.80	
13	Waikiki	Distr. Unattended	115.00	13.80	
14	West Side	Trans. Unattended	230.00	115.00	13.80
15	Other: 28 substa less than 10MVA	Distr. Unattended			
16					
17	STATE OF IDAHO				
18	Appleway	Dist. Unattended	115.00	13.80	
19	Avondale	Dist. Unattended	115.00	13.80	
20	Benewah	Trans. Unattended	230.00	115.00	13.80
21	Big Creek	Distr. Unattended	115.00	13.80	
22	Blue Creek	Distr. Unattended	115.00	13.80	
23	Bunker Hill Limited	Distr. Unattended	115.00	13.80	
24	Cabinet Gorge (Switchyard)	Trans. Unattended	230.00	115.00	13.80
25	Clark Fork	Distr. Unattended	115.00	21.80	
26	Coeur d'Alene 15th Ave	Distr. Unattended	115.00	13.80	
27	Cottonwood	Distr. Unattended	115.00	24.90	
28	Dalton	Distr. Unattended	115.00	13.80	
29	Grangeville	Distr. Unattended	115.00	13.80	
30	Holbrook	Distr. Unattended	115.00	13.80	
31	Huetter	Distr. Unattended	115.00	13.80	
32	Idaho Road	Distr Unattended	115.00	13.80	
33	Juliaetta	Distr. Unattended	115.00	13.80	
34	Kamiah	Dist. Unattended	115.00	13.80	
35	Kooskia	Distr. Unattended	115.00	13.80	
36	Lolo	Tran & Dist Unattnd	230.00	115.00	13.80
37	Moscow	Distr. Unattended	115.00	13.80	
38	Moscow 230Kv	Tran & Dist Unattnd	230.00	115.00	13.80
39	North Moscow	Distr. Unattended	115.00	13.80	
40	North Lewiston 230kV	Trans Unattended	230.00	115.00	13.80

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
24	2		Two Stage Fan	2	40	1
30	2		Two Stage Fan	2	54	2
24	2		Two Stage Fan	2	40	3
150	1		Two Stage Fan	1	250	4
12	1		Frcd Oil & Air Fan	1	20	5
30	2		Two Stage Fan	2	50	6
12	1		Two Stage Fan	1	20	7
30	2		Two Stage Fan	2	50	8
33	2		Two Stage Fan & Caps	50	55	9
12	1		Two Stage Fan	1	20	10
54	3		Two Stg Fan & Cap	103	90	11
36	2		Two Stg Fan	2	60	12
24	2		Two Stage Fan	2	40	13
250	2					14
166	34	3				15
						16
						17
36	2		Two Stage Fan	2	60	18
12	1		Two Stage Fan	1	20	19
75	1		Two Stage Fan & Caps	223	125	20
18	2		Portable Fan	2	22	21
20	3	1				22
12	1		Frcd Air Fan	1	16	23
75	1		Two Stage Fan	1	125	24
10	1		Frcd Air Fan	1	13	25
36	2		Two Stage Fan	2	60	26
12	1		Two Stage Fan	1	20	27
24	2		FrcOil/Air2StgFan	2	40	28
25	4		FrcdOil/Air/Pt Fan&C	17	34	29
12	1		Two Stage Fan	1	20	30
12	1		Two Stage Fan	1	20	31
12	1		Two Stage Fan	1	20	32
12	1		Frcd Oil & Air Fan	1	20	33
12	1		Two Stage Fan	1	20	34
15	3		Frcd Air Fan	3	20	35
262	3		Frcd Oil/Air/Two Stg	1	270	36
24	2		FrOil/Air/2Stg Fan	2	40	37
162	2		Two Stage Fan & Caps	48	262	38
12	1		Two Stage Fan	1	20	39
250	1	1	Capacitors	48		40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	North Lewiston	Distr. Unattended	115.00	13.80	
2	Oden	Distr. Unattended	115.00	21.80	
3	Oldtown	Distr. Unattended	115.00	21.80	
4	Orofino	Distr. Unattended	115.00	13.80	
5	Osburn	Distr. Unattended	115.00	13.80	
6	Pine Creek	Tran & Dist Unattnd	230.00	115.00	13.80
7	Pleasant View	Distr. Unattended	115.00	13.80	
8	Plummer	Dist Unattended	115.00	13.80	
9	Post Falls	Distr. Unattended	115.00	13.80	
10	Potlatch	Distr. Unattended	115.00	13.80	
11	Prarie	Distr. Unattended	115.00	13.80	
12	Priest River	Distr. Unattended	115.00	20.80	
13	Rathdrum	Trans & Distr Unattd	230.00	115.00	13.80
14	Sagle	Dist. Unattended	115.00	20.80	
15	Sandpoint	Distr. Unattended	115.00	20.80	
16	South Lewiston	Distr. Unattended	115.00	13.80	
17	Sweetwater	Distr. Unattended	115.00	24.90	
18	St. Maries	Distr. Unattended	115.00	23.90	
19	Tenth & Stewart	Distr. Unattended	115.00	13.80	
20	Wallace	Distr. Unattended	115.00	13.80	
21	Other: 13 substa less than 10 MVA	Distr. Unattended			
22					
23	STATE OF MONTANA				
24	1 substation less than 10 MVA	Distr. Unattended			
25					
26	SUBSTA. @ GENERATING PLANTS				
27	STATE OF WASHINGTON				
28	Boulder Park	Trans. Attended	115.00	13.80	
29	Kettle Falls	Trans. Attended	115.00	13.80	
30	Long Lake	Trans. Attended	115.00	4.00	
31	Nine Mile	Trans. Attended	115.00	13.80	
32	Little Falls	Trans. Attended	115.00	4.00	
33	Northeast	Trans. Attended	115.00	13.80	
34	Post Street	Trans. Attended	13.80	4.00	
35					
36	STATE OF IDAHO				
37	Cabinet Gorge (HED)	Trans. Attended	230.00	13.80	
38	Post Falls	Trans. Attended	115.00	2.30	
39	Rathdrum	Trans. Attended	115.00	13.80	
40	STATE OF MONTANA				

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SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
10	3					1
10	1		Frcd Air Fan	1	13	2
18	2		Frcd Air Fan	2	22	3
20	2		Frcd Oil & Air Fan	1	28	4
12	1		Portable Fan	1	15	5
262	3		Two Stg Fan/Capacito	45	270	6
12	1		Two Stage Fan	1	20	7
12	1		Two Stage Fan	1	20	8
18	1		Two Stage Fan	1	30	9
15	2		Portable Fan	2	19	10
12	1		Frcd Oil & Air Fan	1	20	11
10	1		Frcd Air Fan	1	13	12
474	4		Frcd Oil & Air Fan	50	490	13
12	1		Two Stage Fan	1	20	14
30	3		Frcd Air Fan	3	38	15
27	4		Port Fan/FrcdOil/Air	4	39	16
12	1		Frcd Oil & Air Fan	1	20	17
24	2		Two Stage Fan	2	40	18
30	2		Frcd Oil/Air/Two Stg	2	50	19
10	3					20
70	13					21
						22
						23
5	1					24
						25
						26
						27
36	1		Two Stage Fan	1	60	28
34	1	1	Two Stage Fan	1	62	29
80	4	1				30
12	1					31
24	2		Frcd Oil & Air Fan	2	40	32
36	1		Two Stage Fan	1	60	33
35	2					34
						35
						36
300	6	1	Frcd Oil and Air Fan			37
16	2		Frcd Air/Oil/Air Fan	2	21	38
114	2	1	Two Stage Fan	2	190	39
						40

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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Noxon	Trans. Attended	230.00	13.80	
2					
3	STATE OF OREGON				
4	Coyote Springs II	Trans. Attended	500.00	13.80	18.00
5					
6	SUMMARY:				
7	Washington:				
8	4 subs	Trans. Unattended			
9	75 subs	Distr. Unattended			
10	1 subs	Tran & Dist Unattnd			
11	7 subs	Trans. Attended			
12	Idaho:				
13	3 subs	Trans. Unattended			
14	48 subs	Distr. Unattended			
15	4 subs	Tran & Dist Unattnd			
16	3 subs	Trans. Attended			
17	Montana: 1 sub	Trans. Attended			
18	1 sub	Distr. Unattended			
19	Oregon: 1 sub	Trans. Unattended			
20	System: 148 subs				
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
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40					

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
435	9	1	Two Stage Fan	2	635	1
						2
						3
213	1	1	Two Stage fan	1	355	4
						5
						6
						7
850						8
1184						9
536						10
257						11
						12
400						13
668						14
1160						15
430						16
435						17
5						18
213						19
6138						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
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						32
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						35
						36
						37
						38
						39
						40

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TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	NONE			
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	NONE			
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
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