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

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2016)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2016)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2016)

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 2014/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 2014/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* (509) 495-4256	09 This Report Is (1) ☒ An Original (2) ☐ A Resubmission	10 Date of Report *(Mo, Da, Yr)* 04/15/2015

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 Christy Burmeister-Smith 02 Title VP, Controller, Prin. Acctg Officer	03 Signature Christy Burmeister-Smith	04 Date Signed *(Mo, Da, Yr)* 04/15/2015

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

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/Q4

LIST OF SCHEDULES (Electric Utility)

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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".

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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".

Stockholders' Reports Check appropriate box:

[X] Two copies will be submitted

[ ] No annual report to stockholders is prepared

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report *(Mo, Da, Yr)* 04/15/2015	Year/Period of Report End of 2014/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

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	04/15/2015	End of 2014/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 II, Inc.	Inactive	100	Subsidiary of
22				Pentzer Corporation
23				
24	Bay Area Manufacturing, Inc.	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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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 capacity	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				

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	04/15/2015	End of 2014/Q4

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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Salix, Inc.	Liquified natural gas	100	Subsidiary of
2		operations		Avista Capital
3				
4	Alaska Energy and Resources Company (AERC)	Parent company of Alaska	100	Subsidiary of
5		operations.		Avista Corp.
6				
7	Alaska Electric Light and Power Company	Utility operations based in	100	Subsidiary of
8		the City and Borough of		AERC
9		Juneau, AK		
10				
11	AJT Mining Properties, Inc.	Inactive mining company	100	Subsidiary of
12		holding certain properties in		AERC
13		the City and Borough of		
14		Juneau, AK		
15				
16	Snettisham Electric Company	Holds certain rights to	100	Subsidiary of
17		purchase the Snettisham		AERC
18		Hydroelectric project in the		
19		City and Borough of		
20		Juneau, AK		
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Schedule Page: 103 Line No.: 4 Column: a

Ecova, Inc. was disposed of on June 30, 2014. See Footnote 4 of the Notes to Financial Statements on page 122-123 for further information.

Schedule Page: 103.2 Line No.: 4 Column: a

This company was acquired on July 1, 2014. See Note 3 of the Notes to Financial Statements on page 122-123 for further information.

Schedule Page: 103.2 Line No.: 7 Column: a

This company was acquired on July 1, 2014. See Note 3 of the Notes to Financial Statements on page 122-123 for further information.

Schedule Page: 103.2 Line No.: 11 Column: a

This company was acquired on July 1, 2014. See Note 3 of the Notes to Financial Statements on page 122-123 for further information.

Schedule Page: 103.2 Line No.: 16 Column: a

This company was acquired on July 1, 2014. See Note 3 of the Notes to Financial Statements on page 122-123 for further information.

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	04/15/2015	End of 2014/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		
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		
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	Senior Vice President, responsible for Energy	J. R. Thackston	
34	Resources (effective 1/2014)		
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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) 04/15/2015	Year/Period of Report End of 2014/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 (resigned from Board 2/2014)	999 Third Ave., Suite 4300, Seattle, WA 98104
11		
12	John F. Kelly***	851 Georgia Ave., Winter Park, FL 33143
13		
14	Heidi B. Stanley	P.O. Box 2884, Spokane, WA 99220
15		
16	R. John Taylor***	111 Main Street, Lewiston, ID 83501
17		
18	Marc F. Racicot	28013 Swan Cove Dr., Big Fork, MT 59911
19		
20	Rebecca A. Klein	611 S. Congress Ave., Suite 125, Austin, TX 78704
21		
22	Janet D. Widmann (joined the Board 8/2014)	50 Beale St., 23rd Fl., San Francisco, CA 94105
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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	04/15/2015	End of 2014/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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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

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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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on 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 completed on July 1, 2014. This merger was approved by each of our various Commissions on the following Orders: UTC U-132222 Order 1, IPUC Order 32991, OPUC Order 14-112 and RCA Order U-13-197. Refer to Note 3 of the Notes to Financial Statements for further details regarding this merger transaction.
3. Avista Corp. sold its interest in Ecova, Inc. (Ecova), effective June 30, 2014. Ecova was the primary unregulated subsidiary of Avista Corp. and no Commission authorization was required. Refer to Note 4 of the Notes to Financial Statements for further details regarding this sales transaction.
4. None
5. None
6. Avista Corp. has a committed line of credit with various financial institutions in the total amount of $400 million. In April 2014, the Company amended this committed line of credit agreement to extend the expiration date to April 2019. The amendment also provides the Company the option to request an extension for an additional one or two years beyond April 2019, provided there is no event of default prior to the requested extension and the requested extension does not cause the remaining term until the expiration date to exceed five years. The amendment did not change the amount of the committed line of credit. 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, 2014 and December 31, 2013 (dollars in thousands):

	December 31, 2014	December 31, 2013
Balance outstanding at end of period	$105,000	$171,000
Letters of credit outstanding at end of period	$32,579	$27,434

In December 2014, Avista Corp. issued $60.0 million of first mortgage bonds to three institutional investors in a private placement transaction. The first mortgage bonds bear an interest rate of 4.11 percent and mature in 2044. The total net proceeds from the sale of the new bonds were used to repay a portion of the borrowings outstanding under the Company's $400.0 million committed line of credit and for general corporate purposes. 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 2.3% for non-exempt employees effective February 24, 2014. Average annual wage increases were 3.0% for exempt employees effective February 24, 2014. Officers received average increases of 3.8% effective March 1, 2014. Certain bargaining unit employees received increases of 3.25% effective April 1, 2014.
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. 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.

On July 8, 2014, Avista Corp.'s Board of Directors decided to increase the number of board members from 9 to 10 and elected Janet D. Widmann to fill the vacancy and serve as a director on the board effective August 2, 2014.

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

Effective February 2015, Kevin J Christie was promoted to Vice President of Customer Solutions. He had previously held various other management and staff positions with the Company since 2005.

14. Proprietary capital is not less than 30 percent.

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	4,513,148,224	4,280,005,611
3	Construction Work in Progress (107)	200-201	223,330,993	157,258,690
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		4,736,479,217	4,437,264,301
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	1,573,767,832	1,491,212,830
6	Net Utility Plant (Enter Total of line 4 less 5)		3,162,711,385	2,946,051,471
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)		3,162,711,385	2,946,051,471
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)		5,288,635	5,438,891
19	(Less) Accum. Prov. for Depr. and Amort. (122)		194,911	920,905
20	Investments in Associated Companies (123)		12,047,000	12,047,000
21	Investment in Subsidiary Companies (123.1)	224-225	148,255,851	112,232,104
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)		11,525,386	13,980,638
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		11,488,865	10,897,909
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	853,757
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	19,574,858
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		188,410,826	174,104,252
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		1,535,172	3,949,469
36	Special Deposits (132-134)		6,832,649	19,283,082
37	Working Fund (135)		971,206	864,092
38	Temporary Cash Investments (136)		15,508,864	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		163,095,696	182,617,384
41	Other Accounts Receivable (143)		5,091,552	8,417,179
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		4,828,572	4,830,036
43	Notes Receivable from Associated Companies (145)		0	5,720,836
44	Accounts Receivable from Assoc. Companies (146)		401,126	286,696
45	Fuel Stock (151)	227	4,116,727	3,170,050
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	29,419,472	26,655,710
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	04/15/2015	End of 2014/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)		28,731,498	13,028,710
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		13,368,084	7,938,050
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		31,080	30,982
60	Rents Receivable (172)		1,740,695	1,360,262
61	Accrued Utility Revenues (173)		0	0
62	Miscellaneous Current and Accrued Assets (174)		614,449	752,953
63	Derivative Instrument Assets (175)		1,524,582	3,875,269
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	853,757
65	Derivative Instrument Assets - Hedges (176)		460,316	33,544,588
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	19,574,858
67	Total Current and Accrued Assets (Lines 34 through 66)		268,614,596	286,236,661
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		12,476,292	12,505,134
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	576,247,558	381,581,939
73	Prelim. Survey and Investigation Charges (Electric) (183)		165,866	875,153
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)		28,145	0
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	11,803,983	13,312,292
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)		17,356,781	19,417,103
82	Accumulated Deferred Income Taxes (190)	234	123,261,474	70,239,422
83	Unrecovered Purchased Gas Costs (191)		-3,921,214	-12,074,780
84	Total Deferred Debits (lines 69 through 83)		737,418,885	485,856,263
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		4,364,147,768	3,899,240,723

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	04/15/2015	end of 2014/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	984,400,740	869,342,827
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	-9,520,161	8,089,025
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	-25,079,123	-19,561,527
11	Retained Earnings (215, 215.1, 216)	118-119	507,257,161	413,009,873
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-15,658,553	-5,918,024
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)	-7,887,881	-5,819,930
16	Total Proprietary Capital (lines 2 through 15)		1,483,670,429	1,298,265,298
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,436,700,000	1,376,700,000
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)		186,550	195,433
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		1,308,604	1,482,644
24	Total Long-Term Debt (lines 18 through 23)		1,403,424,946	1,343,259,789
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	4,193,852
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		240,000	240,000
29	Accumulated Provision for Pensions and Benefits (228.3)		189,489,100	122,512,892
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		5,855,845	2,489,686
32	Long-Term Portion of Derivative Instrument Liabilities		22,093,166	18,355,040
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		40,857,456	0
34	Asset Retirement Obligations (230)		3,028,391	2,847,207
35	Total Other Noncurrent Liabilities (lines 26 through 34)		261,563,958	150,638,677
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		105,000,000	171,000,000
38	Accounts Payable (232)		111,077,010	107,675,819
39	Notes Payable to Associated Companies (233)		9,934,843	0
40	Accounts Payable to Associated Companies (234)		714,039	810,911
41	Customer Deposits (235)		4,977,259	3,393,269
42	Taxes Accrued (236)	262-263	-10,725,297	22,103,801
43	Interest Accrued (237)		13,595,667	13,444,066
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	04/15/2015	end of 2014/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)		50,226	115,213
48	Miscellaneous Current and Accrued Liabilities (242)		57,483,998	55,243,462
49	Obligations Under Capital Leases-Current (243)		4,193,852	297,339
50	Derivative Instrument Liabilities (244)		40,138,121	29,230,059
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		22,093,166	18,355,041
52	Derivative Instrument Liabilities - Hedges (245)		48,202,046	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		40,857,456	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		321,691,142	384,958,898
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		1,864,508	1,459,117
57	Accumulated Deferred Investment Tax Credits (255)	266-267	12,157,507	12,387,031
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	21,269,740	25,359,333
60	Other Regulatory Liabilities (254)	278	48,834,355	71,742,330
61	Unamortized Gain on Reaquired Debt (257)		2,096,044	2,225,581
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		582,721,352	447,100,235
64	Accum. Deferred Income Taxes-Other (283)		224,853,787	161,844,434
65	Total Deferred Credits (lines 56 through 64)		893,797,293	722,118,061
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		4,364,147,768	3,899,240,723

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	04/15/2015	End of 2014/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	1,572,976,141	1,574,987,368		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	1,034,794,124	1,054,508,447		
5	Maintenance Expenses (402)	320-323	65,573,481	60,947,443		
6	Depreciation Expense (403)	336-337	112,562,200	105,822,752		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	16,874,247	13,800,853		
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)		1,871,414	12,986,972		
13	(Less) Regulatory Credits (407.4)		10,536,841	13,582,146		
14	Taxes Other Than Income Taxes (408.1)	262-263	93,076,918	88,262,771		
15	Income Taxes - Federal (409.1)	262-263	-55,133,870	39,972,039		
16	- Other (409.1)	262-263	-1,858,807	2,066,338		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	135,547,906	31,154,269		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	4,060,583	4,770,686		
19	Investment Tax Credit Adj. - Net (411.4)	266	-229,524	-238,869		
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)		1,388,579,712	1,391,029,230		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		184,396,429	183,958,138		

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	04/15/2015	End of 2014/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
1,015,103,873	1,049,456,902	557,872,268	525,530,466			2
						3
584,239,618	635,615,026	450,554,506	418,893,421			4
51,160,378	48,867,669	14,413,103	12,079,774			5
89,097,411	84,631,445	23,464,789	21,191,307			6
						7
13,008,487	10,778,960	3,865,760	3,021,893			8
99,047	99,047					9
						10
						11
1,535,950	12,125,143	335,464	861,829			12
10,108,656	13,080,536	428,185	501,610			13
69,580,534	66,342,004	23,496,384	21,920,767			14
-27,894,913	31,663,448	-27,238,957	8,308,591			15
-716,972	1,388,109	-1,141,835	678,229			16
94,097,395	25,700,222	41,450,511	5,454,047			17
4,203,362	4,871,648	-142,779	-100,962			18
-195,528	-199,113	-33,996	-39,756			19
						20
						21
						22
						23
						24
859,699,389	899,059,776	528,880,323	491,969,454			25
155,404,484	150,397,126	28,991,945	33,561,012			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	04/15/2015	End of 2014/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)		184,396,429	183,958,138		
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)		-17,531	-13,172		
34	(Less) Expenses of Nonutility Operations (417.1)		9,837,245	10,644,789		
35	Nonoperating Rental Income (418)		-1,100	-3,699		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	82,361,715	4,593,239		
37	Interest and Dividend Income (419)		1,845,367	2,432,397		
38	Allowance for Other Funds Used During Construction (419.1)		8,678,360	6,065,628		
39	Miscellaneous Nonoperating Income (421)					
40	Gain on Disposition of Property (421.1)		290,479			
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		83,320,045	2,429,604		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		38,668			
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		3,879,397	3,320,437		
46	Life Insurance (426.2)		2,060,570	2,599,896		
47	Penalties (426.3)		-24,718	109,224		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,679,329	1,605,677		
49	Other Deductions (426.5)		3,295,162	4,366,477		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		10,928,408	12,001,711		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	150,614	172,447		
53	Income Taxes-Federal (409.2)	262-263	-314,356	-481,927		
54	Income Taxes-Other (409.2)	262-263	2,579,615	-1,004,519		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	-1,467,880	-1,731,439		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	6,039,386	5,632,031		
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)		-5,091,393	-8,677,469		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		77,483,030	-894,638		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		67,341,170	68,485,495		
63	Amort. of Debt Disc. and Expense (428)		424,830	448,328		
64	Amortization of Loss on Reaquired Debt (428.1)		3,219,369	3,373,538		
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)		735,498	750,512		
68	Other Interest Expense (431)		2,037,957	2,613,463		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		3,911,170	3,675,786		
70	Net Interest Charges (Total of lines 62 thru 69)		69,838,771	71,986,667		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		192,040,688	111,076,833		
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)		192,040,688	111,076,833		

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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	04/15/2015	End of 2014/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		403,295,872	376,139,703
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11	Repurchase from Common Stock		-39,369,910	
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)		-39,369,910	
16	Balance Transferred from Income (Account 433 less Account 418.1)		109,678,973	98,317,714
17	Appropriations of Retained Earnings (Acct. 436)			
18	Excess Earnings		-4,555,754	
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-4,555,754	
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			-78,313,788	(73,276,102)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-78,313,788	(73,276,102)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		102,252,013	2,114,557
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		492,987,406	403,295,872
	APPROPRIATED RETAINED EARNINGS (Account 215)			

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	04/15/2015	End of 2014/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)
39			14,269,755	9,714,001
40				
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)		14,269,755	9,714,001
	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)		14,269,755	9,714,001
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		507,257,161	413,009,873
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		-5,918,024	(747,337)
50	Equity in Earnings for Year (Credit) (Account 418.1)		82,361,715	4,593,239
51	(Less) Dividends Received (Debit)			
52			-92,102,244	(9,763,926)
53	Balance-End of Year (Total lines 49 thru 52)		-15,658,553	(5,918,024)

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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)	192,040,688	111,076,833
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	126,986,417	117,173,574
5	Amortization of deferred power and natural gas costs	-14,611,016	-9,407,533
6	Amortization of debt expense	3,635,317	3,812,982
7	Amortization of investment in exchange power	2,450,031	2,450,031
8	Deferred Income Taxes (Net)	123,968,809	20,846,650
9	Investment Tax Credit Adjustment (Net)	-229,524	-226,027
10	Net (Increase) Decrease in Receivables	17,645,850	-30,523,370
11	Net (Increase) Decrease in Inventory	-19,413,226	2,417,981
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-40,191,116	-4,903,140
14	Net (Increase) Decrease in Other Regulatory Assets	10,925,414	-899,982
15	Net Increase (Decrease) in Other Regulatory Liabilities	4,616,847	7,774,282
16	(Less) Allowance for Other Funds Used During Construction	8,678,360	6,065,628
17	(Less) Undistributed Earnings from Subsidiary Companies	82,361,715	4,593,239
18	Other (provide details in footnote):	-22,727,203	-4,736,292
19	Allowance for doubtful accounts	5,200,000	4,792,409
20	Changes in other non-current assets and liabilities	-15,740,101	-7,470,522
21	Write-off of Reardan wind generation assets		2,533,578
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	283,517,112	204,052,587
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-323,931,192	-294,363,192
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)	-323,931,192	-294,363,192
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38	Federal grant payments received	2,529,902	3,409,479
39	Investments in and Advances to Assoc. and Subsidiary Companies	15,444,378	-4,891,325
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43	Cash paid for acquisition	-4,697,090	
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	04/15/2015	End of 2014/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	94,098	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	-373,865	6,167
55	Dividends received from subsidiaries	197,000,000	
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-113,933,769	-295,357,701
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	60,000,000	90,000,000
62	Preferred Stock		
63	Common Stock	4,059,874	4,609,006
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)	64,059,874	94,609,006
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-297,339	-50,258,586
74	Preferred Stock		
75	Common Stock	-79,855,898	
76	Other (provide details in footnote):	107,021	
77	Debt issuance costs	-1,510,532	-531,294
78	Net Decrease in Short-Term Debt (c)	-66,000,000	119,000,000
79	Cash received (paid) for settlement of interest rate swaps	5,429,000	2,900,680
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-78,313,788	-73,276,102
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-156,381,662	92,443,704
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	13,201,681	1,138,590
87			
88	Cash and Cash Equivalents at Beginning of Period	4,813,561	3,674,971
89			
90	Cash and Cash Equivalents at End of period	18,015,242	4,813,561

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Power and natural gas deferrals	1,104,752
Change in special deposits	(23,301,320)
Change in other current assets	(5,671,849)
Non-cash stock compensation	6,006,850
Cash paid for foreign currency hedges	20,692
Change in Coyote Springs 2 O&M LTSA	(1,082,230)
Preliminary survey and investigation costs	709,287
Tax shortfalls from stock compensation	(513,385)

Schedule Page: 120 Line No.: 18 Column: c

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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Excess tax benefits	107,021

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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	04/15/2015	End of 2014/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 primarily an electric and natural gas utility with certain other business ventures. Avista Corp. provides electric distribution and transmission, and natural gas distribution services in parts of eastern Washington and northern Idaho. Avista Corp. also provides natural gas distribution service in parts of northeastern and southwestern Oregon. Avista Corp. has electric generating facilities in Washington, Idaho, Oregon and Montana. Avista Corp. also supplies electricity to a small number of customers in Montana, most of whom are employees who operate Avista Corp.'s Noxon Rapids generating facility.

On July 1, 2014, Avista Corp. completed its acquisition of Alaska Energy and Resources Company (AERC), and as of that date, AERC is a wholly-owned subsidiary of Avista Corp. The primary subsidiary of AERC is Alaska Electric Light and Power Company (AEL&P), comprising the regulated utility operations in Alaska. The results of AERC for only the final six months of 2014 are included in the overall results of Avista Corp. See Note 3 for information regarding the acquisition of AERC.

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). During the first half of the year, Avista Capital's subsidiaries included Ecova, Inc. (Ecova), which was an 80.2 percent owned subsidiary prior to its disposition on June 30, 2014. Ecova was a provider of energy efficiency and other facility information and cost management programs and services for multi-site customers and utilities throughout North America. See Note 4 for information regarding the disposition of Ecova.

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

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

- unbilled revenues.

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

System of Accounts

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

Regulation

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

Operating Revenues

Operating 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. Our estimate of unbilled revenue is based on:

- the number of customers,
- current rates,
- meter reading dates,
- actual native load for electricity, and
- actual throughput for natural gas.

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

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

	2014	2013
Unbilled accounts receivable	$ 78,077	$ 81,059

Advertising Expenses

The Company expenses advertising costs as incurred. Advertising expenses were not a material portion of the Company's operating expenses in 2014 and 2013.

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:

2014	2013

Ratio of depreciation to average depreciable property	2.97%	2.90%

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

	Avista Corp.
Electric thermal/other production	40
Hydroelectric production	79
Electric transmission	58
Electric distribution	35
Natural gas distribution property	46

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):

	2014	2013
Utility taxes	$ 57,599	$ 55,565

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:

	2014	2013
Effective AFUDC rate	7.64%	7.64%

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 a derivative depends on the intended use of such derivative and the resulting designation.

The UTC and the IPUC issued accounting orders authorizing Avista Corp. to offset energy commodity derivative assets or liabilities with a regulatory asset or liability. This accounting treatment is intended to defer the recognition of mark-to-market gains and losses on energy commodity transactions until the period of delivery. 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 periods 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. 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.

For interest rate swap agreements, each period Avista Corp. records all mark-to-market gains and losses as assets and liabilities and records offsetting regulatory assets and liabilities, such that there is no income statement impact. This is similar to the treatment of energy commodity derivatives described above. 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.

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 hydroelectric 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 Company typically calculates the earnings in excess of the specified rate of return on an annual basis, usually during the second quarter.

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

	2014	2013
Appropriated retained earnings	$ 14,270	$ 9,714

Operating Leases

The Company has multiple lease arrangements involving various assets, with minimum terms ranging from 1 to forty-five years. Future minimum lease payments required under operating leases having initial or remaining noncancelable lease terms in excess of one year were not material as of December 31, 2014.

Equity in Earnings of Subsidiaries

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

	2014	2013
Avista Capital	$ 79,183	$ 4,593
Alaska Energy and Resources Company	3,179	—
Total equity in earnings of subsidiary companies	$ 82,362	$ 4,593

Avista Capital, a wholly owned subsidiary of Avista Corp., is the parent company of all of the subsidiary companies, except Spokane Energy and AERC (and its subsidiaries). Avista Capital's subsidiaries and investments include sheet metal fabrication, venture fund investments, real estate investments and Ecova prior to its disposition on June 30, 2014.

AERC, a wholly-owned subsidiary of Avista Corp. acquired on July 1, 2014, is the parent company to all the Alaska subsidiary companies. The primary subsidiary of AERC is AEL&P, comprising the regulated utility operations in Alaska. Also, AERC owns AJT Mining Properties, Inc., an inactive mining company holding certain properties.

Subsequent Events

Management has evaluated the impact of events occurring after December 31, 2014 up to February 25, 2015, the date that Avista Corp.'s U.S. GAAP financial statements were issued and has updated such evaluation for disclosure purposes through April 15, 2015. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

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 material loss may be incurred. See Note 17 for further discussion of the Company's commitments and contingencies.

NOTE 2. NEW ACCOUNTING STANDARDS

In May 2014, the FASB issued ASU No. 2014-09, "Revenue from Contracts with Customers (Topic 606)," which outlines a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. The core principle of the revenue model is that an entity identifies the various performance obligations in a contract, allocates the transaction price among the performance obligations and recognizes revenue as the entity satisfies the performance obligations. This ASU is effective for periods beginning after December 15, 2016 and early adoption is not permitted. However, while this ASU is not effective until 2017, it will require retroactive application to all periods presented in the financial statements. As such, at adoption in 2017, amounts in 2015 and 2016 may have to be revised or a cumulative adjustment to opening retained earnings may have to be recorded. The Company is evaluating this standard and cannot, at this time, estimate the potential impact to its future financial condition, results of operations and cash flows.

In August 2014, the FASB issued ASU No. 2014-15, "Presentation of Financial Statements - Going Concern (ASC Subtopic 205-40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern." The new standard provides guidance around management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern within one year of the date the financial statements are issued. The Company must provide certain disclosures if conditions or events raise substantial doubt about the Company's ability to continue as a going concern. The new standard is effective for periods beginning after December 15, 2016; however, early adoption is permitted. The Company evaluated this standard and determined that it will not early adopt this standard. As such, there is no impact to the Company's financial condition, results of operations and cash flows in the current year.

NOTE 3. BUSINESS ACQUISITIONS

Alaska Energy and Resources Company

On July 1, 2014, the Company completed its acquisition of AERC, based in Juneau, Alaska. As of July 1, 2014 AERC is a wholly-owned subsidiary of Avista Corp.

The primary subsidiary of AERC is AEL&P, a regulated utility which provides electric services to 16,394 customers in the City and Borough of Juneau, Alaska. As of December 31, 2014, AEL&P has 59 full-time employees. AEL&P has a firm retail peak load of approximately 68 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. AEL&P also has 93.9 MW of diesel generating capacity to provide back-up service to firm customers when necessary.

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

The purpose of the acquisition was to expand and diversify Avista Corp.'s energy assets and deliver long-term value to its customers, communities and investors.

In connection with the closing, on July 1, 2014 Avista Corp. issued 4,500,014 new shares of common stock to the shareholders of AERC based on a contractual formula that resulted in a price of $32.46 per share, reflecting a purchase price of $170.0 million, plus acquired cash, less outstanding debt and other closing adjustments.

The $32.46 price per share of Avista Corp. common stock was determined based on the average closing stock price of Avista Corp. common stock for the 10 consecutive trading days immediately preceding, but not including, the trading day prior to July 1, 2014. This value was used solely for determining the number of shares to issue based on the adjusted contract closing price (see reconciliation below). The fair value of the consideration transferred at the closing date was based on the closing stock price of Avista Corp. common stock on July 1, 2014, which was $33.35 per share.

On October 1, 2014, a working capital adjustment was made in accordance with the agreement and plan of merger which resulted in Avista Corp. issuing an additional 1,427 shares of common stock to the shareholders of AERC. The number of shares issued on October 1, 2014 was based on the same contractual formula described above. The fair value of the new shares issued in October was $30.71 per share, which was the closing stock price of Avista Corp. common stock on that date.

The contract acquisition price and the fair value of consideration transferred for AERC were as follows (in thousands, except "per share" and number of shares data):

		July 1, 2014
Contract acquisition price (using the calculated $32.46 per share common stock price)		
Gross contract price	$	170,000
Acquired cash		19,704
Acquired debt (excluding capital lease obligation)		(38,832)
Other closing adjustments (including the working capital adjustment)		(58)
Total adjusted contract price	$	150,814
Fair value of consideration transferred		
Avista Corp. common stock (4,500,014 shares at $33.35 per share)	$	150,075
Avista Corp. common stock (1,427 shares at $30.71 per share)		44
Cash		4,697
Fair value of total consideration transferred	$	154,816

The assets acquired and liabilities assumed related to the AERC transaction are not included in the FERC Balance Sheets. The information below is presented for information purposes only. The estimated fair value of assets acquired and liabilities assumed as of July 1, 2014 (after consideration of the working capital adjustment) were as follows (in thousands):

		July 1, 2014
Assets acquired:		
Current Assets:		
Cash	$	19,704
Accounts receivable - gross totals $3,928		3,851
Materials and supplies		2,017
Other current assets		999
Total current assets		26,571
Utility Property:		
Utility plant in service		113,964
Utility property under long-term capital lease		71,007
Construction work in progress		3,440
Total utility property		188,411
Other Non-current Assets:		
Non-utility property		6,660
Electric plant held for future use		3,711
Goodwill		52,730
Other deferred charges and non-current assets		5,368
Total other non-current assets		68,469
Total assets	$	283,451
Liabilities Assumed:		
Current Liabilities:		
Accounts payable	$	700
Current portion of long-term debt and capital lease obligations		3,773

Other current liabilities		2,902
Total current liabilities		7,375
Long-term debt		37,227
Capital lease obligations		68,840
Other non-current liabilities and deferred credits		15,193
Total liabilities	$	128,635
Total net assets acquired	$	154,816

The goodwill associated with this acquisition is not deductible for tax purposes.

The majority of AERC's operations are subject to the rate-setting authority of the RCA and are accounted for pursuant to GAAP, including the accounting guidance for regulated operations. The rate-setting and cost recovery provisions currently in place for AERC's regulated operations provide revenues derived from costs, including a return on investment, of assets and liabilities included in rate base. Due to this regulation, the fair values of AERC's assets and liabilities subject to these rate-setting provisions are assumed to approximate their carrying values. There were not any identifiable intangible assets associated with this acquisition. The excess of the purchase consideration over the estimated fair values of the assets acquired and liabilities assumed was recognized as goodwill at the acquisition date. The goodwill reflects the value paid for the expected continued growth of a rate-regulated business located in a defined service area with a constructive regulatory environment, the attractiveness of stable, growing cash flows, as well as providing a platform for potential future growth outside of the rate-regulated electric utility in Alaska.

NOTE 4. DISCONTINUED OPERATIONS

On May 29, 2014, Avista Capital, the non-regulated subsidiary of Avista Corp., entered into a definitive agreement to sell its interest in Ecova to Cofely USA Inc., an indirect subsidiary of GDF SUEZ, a French multinational utility company, and an unrelated party to Avista Corp. The sales transaction was completed on June 30, 2014 for a sales price of $335.0 million in cash, less the payment of debt and other customary closing adjustments. At the closing of the transaction on June 30, 2014, Ecova became a wholly-owned subsidiary of Cofely USA Inc. and the Company will have no further involvement with Ecova after such date.

The purchase price of $335.0 million, as adjusted, was divided among the security holders of Ecova, including minority shareholders and option holders, pro rata based on ownership. Approximately $16.8 million (5 percent of the purchase price) will be held in escrow for 15 months from the closing of the transaction to satisfy certain indemnification obligations under the merger agreement. An additional $1.0 million is being held in escrow pending resolution of adjustments to working capital, which is expected to be resolved in early 2015.

Avista Capital and Cofely USA Inc. agreed to make an election under Section 338(h)(10) of the Internal Revenue Code (Code) of 1986, as amended, with respect to the purchase and sale of Ecova to allocate the merger consideration among the assets of Ecova deemed to have been acquired in the merger.

When all escrow amounts are released, the sales transaction is expected to provide cash proceeds to Avista Corp., net of debt, payment to option and minority holders, income taxes and transaction expenses, of $143.5 million (see reconciliation below) and result in a net gain of $69.7 million. The Company expects to receive the full amount of its portion of the remaining escrow accounts; therefore, these amounts were included in the gain calculation.

The summary of cash proceeds associated with the sales transaction are as follows (in thousands):

Reconciliation of Gross Proceeds		
Contract price	$	335,000
Closing adjustments		3,914

Gross proceeds from sale (1)		338,914
Cash sold in the transaction		(95,932)
Avista Corp. portion of proceeds held in escrow		(13,079)
Gross proceeds from sale of Ecova, net of cash sold	$	229,903

Reconciliation of expected net proceeds		
Gross proceeds from sale (1)	$	338,914
Repayment of long-term borrowings under committed line of credit		(40,000)
Payment to option holders and redeemable noncontrolling interests		(20,871)
Payment to noncontrolling interests		(54,179)
Transaction expenses withheld from proceeds		(5,390)
Avista Corp. portion of proceeds held in escrow		(13,079)
Net proceeds to Avista Capital at transaction closing		205,395
Tax payments made in 2014		(74,842)
Estimated tax payments to be made in 2015		(172)
Avista Corp. portion of proceeds held in escrow to be received in the future		13,079
Total net proceeds related to sales transaction	$	143,460

(1) Of this total amount, approximately $16.8 million will be held in escrow for 15 months from the transaction closing date for any indemnity claims and an additional $1.0 million is being held in escrow pending resolution of adjustments to working capital, which is expected to be resolved in early 2015.

NOTE 5. DERIVATIVES AND RISK MANAGEMENT

Energy Commodity Derivatives

Avista Corp. is exposed to market risks relating to changes in electricity and natural gas commodity prices and certain other fuel prices. Market risk is, in general, the risk of fluctuation in the market price of the commodity being traded and is influenced primarily by supply and demand. Market risk includes the fluctuation in the market price of associated derivative commodity instruments. Avista Corp. utilizes derivative instruments, such as forwards, futures, 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 the Company's resource procurement and management operations in the electric business, the Company engages in an ongoing process of resource optimization, which involves the economic selection from available energy resources to serve 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 derivative 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, the Company makes 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 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, 2014 that are expected to be settled 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
2015	522	2,547	21,111	120,780	326	2,951	3,428	99,023
2016	397	1,071	2,505	70,480	287	1,634	910	56,520
2017	397	—	675	24,230	286	290	—	15,420
2018	397	—	—	3,020	286	—	—	—
2019	235	—	—	1,800	158	—	—	—
Thereafter	—	—	—	—	—	—	—	—

(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 electric and natural gas derivative contracts above will be included in either power supply costs or natural gas supply costs during the period they are settled 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):

	2014	2013
Number of contracts	18	23
Notional amount (in United States dollars)	$ 5,474	$ 8,631
Notional amount (in Canadian dollars)	6,198	9,191

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 manage 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 outstanding as of the balance sheet date indicated below (dollars in thousands):

Balance Sheet Date	Number of Contracts	Notional Amount	Mandatory Cash Settlement Date
December 31, 2014	5	$ 75,000	2015
	5	95,000	2016
	3	45,000	2017
	9	205,000	2018
December 31, 2013	2	50,000	2014
	2	45,000	2015
	2	40,000	2016
	1	15,000	2017
	4	95,000	2018

In October 2014, the Company cash settled two interest rate swap contracts (notional aggregate amount of $50.0 million) and received a total of $5.4 million. The interest rate swap contracts were settled in connection with the pricing of $60.0 million of Avista Corp. first mortgage bonds that were issued in December 2014 (see Note 12). 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.

As of December 31, 2014, the fair value of the outstanding interest rate swaps decreased significantly compared to December 31, 2013 (see the table below). The fair value decrease was the result of a net increase in the notional amount of outstanding swap agreements and a decline in market interest rates below the rates that were fixed in the outstanding swaps. The Company enters into interest rate swaps to reduce uncertainty related to the net effective interest cost for future long-term debt. The Company would be required to make cash payments to settle the interest rate swaps if the fixed rates are higher than prevailing market rates at the date of settlement. Conversely, the Company receives cash to settle its interest rate swaps when prevailing market rates at the time of settlement exceed the fixed swap rates.

Summary of Outstanding Derivative Instruments

Until May 2014, Avista Corp. had a master netting agreement that governed the transactions of multiple affiliated legal entities that were parties to this agreement. This master netting agreement allowed 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. performed cross-commodity netting for each legal entity that was a party to the master netting agreement for presentation in the Balance Sheets; however, Avista Corp. did not perform cross-affiliate netting because the Company believed that cross-affiliate netting may not be enforceable. Therefore, the requirements for cross-affiliate netting under ASC 210-20-45 were not applicable to Avista Corp. As of December 31, 2013, all derivatives for each affiliated entity under this master netting agreement were in a net liability position; therefore, there was no additional netting which required disclosure for the year 2013. In May 2014, this master netting agreement was terminated and each affiliated legal entity is now under their own separate agreement. As of December 31, 2014, the Company no longer has any agreements that allow cross-affiliate netting. The Company has multiple agreements with a variety of entities that allow for cross-commodity netting under ASC 815-10-45. The amounts recorded on the Balance Sheet as of December 31, 2014 and 2013 for these particular entities reflect the offsetting of derivative assets and liabilities where a legal right of offset exists.

The following table presents the fair values and locations of derivative instruments recorded on the Balance Sheet as of December 31, 2014 (in thousands):

		Fair Value			
Derivative	Balance Sheet Location	Gross	Gross	Collateral	Net Asset (Liability) in Balance Sheet
Foreign currency contracts	Derivative instrument liabilities –Hedges	$ 1	$ (21)	$ —	$ (20)
Interest rate contracts	Derivative instrument assets –Hedges	966	(506)	—	460
Interest rate contracts	Derivative instrument liabilities –Hedges	—	(7,325)	—	(7,325)
Interest rate contracts	Long-term portion of derivative liabilities - Hedges	—	(69,737)	28,880	(40,857)
Commodity contracts	Derivative instrument assets current	2,063	(538)	—	1,525
Commodity contracts	Long-term portion of derivative assets	66,421	(97,586)	13,120	(18,045)
Commodity contracts	Long-term portion of derivative liabilities	29,594	(54,077)	2,390	(22,093)
Total derivative instruments recorded on the balance sheet		$ 99,045	$ (229,790)	$ 44,390	$ (86,355)

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
Foreign currency contracts	Derivative instrument assets –Hedges	$ 7	$ (6)	$ —	$ 1
Interest rate contracts	Derivative instrument assets –Hedges	13,968	—	—	13,968
Interest rate contracts	Long-term portion of derivative instrument assets -Hedges	19,575	—	—	19,575
Commodity contracts	Derivative instrument assets current	7,416	(4,394)	—	3,022
Commodity contracts	Long-term portion of derivative assets	7,610	(6,756)	—	854
Commodity contracts	Derivative instrument liabilities current	23,455	(37,306)	2,976	(10,875)
Commodity contracts	Long-term portion of derivative liabilities	17,101	(41,213)	5,756	(18,356)
Total derivative instruments recorded on the balance sheet		$ 89,132	$ (89,675)	$ 8,732	$ 8,189

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, 2014, the Company had cash deposited as collateral of $20.6 million and letters of credit of $14.5 million outstanding related to its energy derivative contracts. The Company also had deposited cash in the amount of $28.9 million and letters of credit of $10.9 million as collateral for its interest rate swap derivative contracts. The Balance Sheet at December 31, 2014 reflects the offsetting of $44.4 million of cash collateral against net derivative positions where a legal right of offset exists. 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, 2014 and December 31, 2013, the Company did not hold any cash as collateral from counterparties under energy derivative contracts.

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, 2014 was $12.9 million. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2014, the Company could be required to post $16.2 million of additional collateral to its counterparties. 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.

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.

The Company enters into bilateral transactions with various counterparties. The Company also trades 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 6. 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):

	2014	2013
Utility plant in service	$ 350,518	$ 349,781
Accumulated depreciation	(239,845)	(239,538)

NOTE 7. ASSET RETIREMENT OBLIGATIONS

The Company records the fair value of a liability for an asset retirement obligation (ARO) in the period in which it is incurred. When the liability is initially recorded, the associated costs of the ARO are capitalized as part of the carrying amount of the related long-lived asset. The liability is accreted to its present value each period and the related capitalized costs are depreciated over the useful life of the related asset. Upon retirement of the asset, the Company either settles the ARO 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 AROs 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):

	2014	2013
Asset retirement obligation at beginning of year	$ 2,859	$ 3,168

Liability settled	(41)	(263)
Accretion expense (income)	210	(46)
Asset retirement obligation at end of year	$ 3,028	$ 2,859

In addition to the AROs described above, on December 19, 2014, the EPA issued its pre-publication version of a final rule regarding the disposal of coal ash. This rule is expected to be published in the Federal Register in early 2015 and the rule is not effective until six months after it is published in the Federal Register; therefore, the Company does not have a revised legal obligation until the third quarter of 2015 when the rule is effective. The Company will continue to review the potential costs of complying with the new coal ash rule and its impacts on the valuation of the Company's ARO at Colstrip to restore ponds to their original states. The Company cannot currently estimate the cost impact of future regulation. If the Company incurs incremental costs as a result of these regulations, it would seek recovery in customer rates.

NOTE 8. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

The Company has a defined benefit pension plan covering the majority of 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 $32.0 million in cash to the pension plan in 2014 and $44.3 million in 2013. The Company expects to contribute $12.0 million in cash to the pension plan in 2015.

In October 2013, the Company revised its defined benefit pension plan such that as of January 1, 2014 the plan is closed to non-union employees hired or rehired by the Company on or after January 1, 2014. Actively employed non-union employees that were hired prior to January 1, 2014 and who were at that date 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 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 changes above, the Company revised the lump sum calculation for non-union participants who retire under the defined benefit pension plan on or after January 1, 2014 to provide retiring employees the election of a lump sum amount equivalent to the present value of the benefits based upon applicable discount rates. In April 2014, the local union in Oregon for the IBEW accepted the above plan changes in the latest collective bargaining agreement, and the plan changes are effective for Oregon union workers hired or rehired on or after April 1, 2014. Employees subject to IBEW local agreements for Washington, Idaho and Montana are not affected by these changes and they continue to be covered by the defined benefit pension plan and are not included in the new defined contribution plan.

For the estimated pension liability and pension costs as of December 31, 2014, the Company adopted the Society of Actuaries' mortality table that was published in 2014 as its base table, which reflects improved longevity of plan participants based on studies of wide populations through 2007 (RP-2014). The Company also adopted a modified form of the Society of Actuaries' MP-2014 mortality improvement scale, which projects improvements to life expectancies after the RP-2014 historic period that ended in 2007. For years subsequent to 2007, the Company reviewed data from other sources, including the Human Mortality Database, maintained by the University of California, Berkley and the Max Planck Institute for Demographic Research, and the Trustee's Report provided by the Social Security Administration. Based on data subsequent to 2007, the mortality improvement scale included in the MP-2014 for the three-year period immediately following its inception (2007) was shown to significantly overstate the actual mortality improvement for those years. As such, the mortality improvement scale the Company adopted assumes a lower rate of improved life expectancy than the MP-2014 scale as published.

The Company also has a Supplemental Executive Retirement Plan (SERP) that provides additional pension benefits to executive officers and certain key employees of the Company. The SERP is intended to provide benefits to individuals 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):

	2015	2016	2017	2018	2019	Total 2020-2024
Expected benefit payments	$ 27,938	$ 29,109	$ 30,157	$ 31,407	$ 32,979	$ 184,794

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 the majority of its retired employees at Avista Corp.. The Company accrues the estimated cost of postretirement benefit obligations during the years that employees provide services. In October 2013, the Company revised the health care benefit plan such that beginning on January 1, 2020, the methods for calculating health insurance premiums for non-union retirees under age 65 and active Company employees were revised to establish separate health insurance premiums for each group. In addition, for non-union employees hired or rehired on or after January 1, 2014, upon retirement the Company will provide access to its retiree medical plan, but will no longer contribute towards their medical premiums and each employee would pay the full cost of premiums upon retirement. In April 2014, the local union in Oregon for the IBEW accepted the above plan changes in the latest collective bargaining agreement, and the plan changes are effective for Oregon union workers hired or rehired on or after April 1, 2014.

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):

	2015	2016	2017	2018	2019	Total 2020-2024
Expected benefit payments	$ 7,138	$ 7,487	$ 7,475	$ 7,589	$ 7,767	$ 36,076

The Company expects to contribute $7.1 million to other postretirement benefit plans in 2015, 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, 2014 and 2013 and the components of net periodic benefit costs for the years ended December 31, 2014 and 2013 (dollars in thousands):

	Pension Benefits		Other Post-retirement Benefits	
	2014	2013	2014	2013
Change in benefit obligation:				
Benefit obligation as of beginning of year	$ 527,004	$ 584,619	$ 108,249	$ 132,541
Service cost	15,757	19,045	1,844	4,144

Interest cost	26,224	23,896	5,226	5,216
Actuarial (gain)/loss	97,128	(78,234)	18,714	(18,017)
Plan change	—	277	—	(10,788)
Transfer of accrued vacation	—	—	437	1,189
Benefits paid	(31,439)	(22,599)	(6,481)	(6,036)
Benefit obligation as of end of year	$ 634,674	$ 527,004	$ 127,989	$ 108,249
Change in plan assets:				
Fair value of plan assets as of beginning of year	$ 481,502	$ 406,061	$ 29,732	$ 25,288
Actual return on plan assets	55,974	52,502	1,580	4,444
Employer contributions	32,000	44,263	—	—
Benefits paid	(30,165)	(21,324)	—	—
Fair value of plan assets as of end of year	$ 539,311	$ 481,502	$ 31,312	$ 29,732
Funded status	$ (95,363)	$ (45,502)	$ (96,677)	$ (78,517)
Unrecognized net actuarial loss	175,596	107,043	82,421	56,885
Unrecognized prior service cost	256	278	(10,379)	(707)
Prepaid (accrued) benefit cost	80,489	61,819	(24,635)	(22,339)
Additional liability	(175,852)	(107,321)	(72,042)	(56,178)
Accrued benefit liability	$ (95,363)	$ (45,502)	$ (96,677)	$ (78,517)
Accumulated pension benefit obligation	$ 551,615	$ 464,432	—	—
Accumulated postretirement benefit obligation:				
For retirees			$ 58,276	$ 52,384
For fully eligible employees			$ 31,843	$ 24,320
For other participants			$ 37,870	$ 31,545

	Pension Benefits		Other Post-retirement Benefits	
	2014	2013	2014	2013
Included in accumulated other comprehensive loss (income) (net of tax):				
Unrecognized prior service cost	$ 166	$ 180	$ (6,747)	$ (7,472)
Unrecognized net actuarial loss	114,138	69,578	53,574	43,988
Total	114,304	69,758	46,827	36,516
Less regulatory asset	(106,484)	(64,925)	(46,759)	(37,116)
Accumulated other comprehensive loss (income) for unfunded benefit obligation for pensions and other postretirement benefit plans	$ 7,820	$ 4,833	$ 68	$ (600)

	Pension Benefits		Other Post-retirement Benefits	
	2014	2013	2014	2013
Weighted average assumptions as of December 31:				
Discount rate for benefit obligation	4.21%	5.10%	4.16%	5.02%
Discount rate for annual expense	5.10%	4.15%	5.02%	4.15%
Expected long-term return on plan assets	6.60%	6.60%	6.40%	6.35%
Rate of compensation increase	4.87%	4.96%		
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	2021	2020
Medical cost trend post-age 65 – initial	7.00%	7.50%
Medical cost trend post-age 65 – ultimate	5.00%	5.00%
Ultimate medical cost trend year post-age 65	2022	2021

	Pension Benefits		Other Post-retirement Benefits	
	2014	2013	2014	2013
Components of net periodic benefit cost:				
Service cost	$ 15,757	$ 19,045	$ 1,844	$ 4,144
Interest cost	26,224	23,896	5,226	5,216
Expected return on plan assets	(32,131)	(27,671)	(1,903)	(1,606)
Transition obligation recognition	—	—	—	—
Amortization of prior service cost	22	319	(1,116)	(149)
Net loss recognition	4,731	13,199	4,289	5,674
Net periodic benefit cost	$ 14,603	$ 28,788	$ 8,340	$ 13,279

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:

	2014	2013
Equity securities	27%	47%
Debt securities	58%	31%
Real estate	6%	6%
Absolute return	9%	12%
Other	—%	4%

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, 2014 and 2013.

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, 2014 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 3,138	$ —	$ 3,138
Fixed income securities:				
U.S. government issues	19,681	—	—	19,681
Corporate issues	104,959	—	—	104,959
International issues	19,935	—	—	19,935
Municipal issues	2,762	7,788	—	10,550
Mutual funds:				
Fixed income securities	157,415	8	—	157,423
U.S. equity securities	103,203	—	—	103,203
International equity securities	40,838	—	—	40,838
Absolute return (1)	15,334	—	—	15,334
Common/collective trusts:				
Real estate	—	—	21,303	21,303
Partnership/closely held investments:				
Absolute return (1)	—	—	36,114	36,114
Private equity funds (3)	—	—	73	73
Real estate	—	—	6,760	6,760
Total	$ 464,127	$ 10,934	$ 64,250	$ 539,311

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

(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, 2014 (dollars in thousands):

	Common/collective trusts	Partnership/closely held investments		
	Real	Absolute	Private equity	Real estate
Balance, as of January 1, 2014	$ 19,735	$ 34,151	$ 377	$ 3,873
Realized gains	24	—	—	595
Unrealized gains (losses)	1,097	1,963	(304)	(644)
Purchases, net	447	—	—	2,936
Balance, as of December 31, 2014	$ 21,303	$ 36,114	$ 73	$ 6,760

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 estate	Absolute return	Private equity funds	Real estate
Balance, as of January 1, 2013	$ 17,596	$ 17,755	$ 660	$ —
Realized gains (losses)	—	—	(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 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 both 2014 and 2013.

The market-related value of other postretirement plan assets was determined as of December 31, 2014 and 2013.

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, 2014 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 3	$ —	$ 3
Mutual funds:				
Fixed income securities	11,968	—	—	11,968
U.S. equity securities	13,210	—	—	13,210
International equity securities	6,131	—	—	6,131
Total	$ 31,309	$ 3	$ —	$ 31,312

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

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, 2014 by $5.2 million and the service and interest cost by $0.4 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, 2014 by $4.1 million and the service and interest cost by $0.3 million.

401(k) Plans and Executive Deferral Plan

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

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

	2014	2013
Employer 401(k) matching contributions	$ 6,741	$ 6,157

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):

	2014	2013
Deferred compensation assets and liabilities	$ 8,677	$ 9,170

NOTE 9. 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 carryforwardsAs of December 31, 2014, the Company had $11.3 million of state tax credit carryforwards. State tax credits expire from 2019 to 2028. 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 2011 and all issues were resolved related to these years. The IRS has not completed an examination of the Company's 2012 and 2013 federal income tax returns. The Company believes that any open tax years for federal or state income taxes will not result in adjustments that would be significant to the financial statements.

The Company did not incur any penalties on income tax positions in 2014 or 2013.

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):

	2014	2013
Regulatory assets for deferred income taxes	$ 100,412	$ 71,421
Regulatory liabilities for deferred income taxes	14,534	9,203

NOTE 10. ENERGY PURCHASE CONTRACTS

Avista Corp. has contracts for the purchase of fuel for thermal generation, natural gas for resale and various agreements for the purchase or exchange of electric energy with other entities. The 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):

	2014	2013
Utility power resources	$ 556,915	$ 524,810

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):

	2015	2016	2017	2018	2019	Thereafter	Total
Power resources	$ 277,474	$ 209,255	$ 144,424	$ 132,897	$ 125,332	$ 860,731	$ 1,750,113
Natural gas resources	82,884	56,504	57,379	52,936	49,304	455,975	754,982
Total	$ 360,358	$ 265,759	$ 201,803	$ 185,833	$ 174,636	$ 1,316,706	$ 2,505,095

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

The above future contractual commitments for power resources include fixed contractual amounts related to the Company's contracts with certain Public Utility Districts (PUD) to purchase portions of the output of certain generating facilities. Although Avista Corp. has no investment in the PUD generating facilities, the fixed contracts obligate Avista Corp. to pay certain minimum amounts whether or not the facilities are operating. The cost of power obtained under the contracts, including payments made when a facility is not operating, is included in utility resource costs in the Statements of Income. The contractual amounts included above consist of Avista Corp.'s share of existing debt service cost and its proportionate share of the variable operating expenses of these projects. The minimum amounts payable under these contracts are based in part on the proportionate share of the debt service requirements of the PUD's revenue bonds for which the Company is indirectly responsible. The Company's total future debt service obligation associated with the revenue bonds outstanding at December 31, 2014 (principal and interest) was $59.4 million.

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

	2015	2016	2017	2018	2019	Thereafter	Total
Contractual obligations	$ 29,133	$ 35,692	$ 28,189	$ 25,659	$ 28,969	$ 193,734	$ 341,376

NOTE 11. NOTES PAYABLE

Avista Corp. has a committed line of credit with various financial institutions in the total amount of $400.0 million. In April 2014, the Company amended this committed line of credit agreement to extend the expiration date to April 2019. The amendment also provides the Company the option to request an extension for an additional one or two years beyond April 2019, provided, 1) there are no default events prior to the requested extension, and 2) the remaining term of agreement, including the requested extension period, does not exceed five years. The amendment did not change the amount of the committed line of credit.

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, 2014, 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):

	2014	2013
Balance outstanding at end of period	$ 105,000	$ 171,000
Letters of credit outstanding at end of period	$ 32,579	$ 27,434
Average interest rate at end of period	0.93%	1.02%

As of December 31, 2014 and 2013, the borrowings outstanding under Avista Corp.'s committed line of credit were classified as short-term borrowings on the Balance Sheet.

NOTE 12. BONDS

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

Maturity Year	Description	Interest Rate	2014	2013
2016	First Mortgage Bonds	0.84%	$ 90,000	$ 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 (1)	(1)	17,000	17,000
2035	First Mortgage Bonds	6.25%	150,000	150,000
2037	First Mortgage Bonds	5.70%	150,000	150,000
2040	First Mortgage Bonds	5.55%	35,000	35,000
2041	First Mortgage Bonds	4.45%	85,000	85,000
2044	First Mortgage Bonds (2)	4.11%	60,000	—
2047	First Mortgage Bonds	4.23%	80,000	80,000
	Total secured bonds		1,436,700	1,376,700
	Settled interest rate swaps (3)		(17,541)	(23,560)
	Secured Pollution Control Bonds held by Avista Corporation (1)		(83,700)	(83,700)
	Total long-term debt		$ 1,335,459	$ 1,269,440

(1) In December 2010, $66.7 million and $17.0 million of the City of Forsyth, Montana Pollution Control Revenue Refunding Bonds (Avista Corporation Colstrip Project) due in 2032 and 2034, respectively, which had been held by Avista Corp. since

2008 and 2009, respectively, were refunded by new bond issues (Series 2010A and Series 2010B). The new bonds were not offered to the public and were purchased by Avista Corp. due to market conditions. The Company expects that at a later date, subject to market conditions, these bonds may be remarketed to unaffiliated investors. So long as Avista Corp. is the holder of these bonds, the bonds will not be reflected as an asset or a liability on Avista Corp.'s Balance Sheets.

(2) In December 2014, Avista Corp. issued $60.0 million of first mortgage bonds to three institutional investors in a private placement transaction. The first mortgage bonds bear an interest rate of 4.11 percent and mature in 2044. The total net proceeds from the sale of the new bonds were used to repay a portion of the borrowings outstanding under the Company's $400.0 million committed line of credit and for general corporate purposes.

(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.

The following table details future long-term debt maturities including advances from associated companies (see Note 13) (dollars in thousands):

	2015	2016	2017	2018	2019	Thereafter	Total
Debt maturities	$ —	$ 90,000	$ —	$ 272,500	$ 90,000	$ 952,047	$ 1,404,547

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, 2014, property additions and retired bonds would have allowed, and the net earnings test would not have prohibited, the issuance of $1.0 billion in aggregate principal amount of additional first mortgage bonds at Avista Corp.

See Note 11 for information regarding first mortgage bonds issued to secure the Company's obligations under its committed line of credit agreement.

NOTE 13. 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:

	2014	2013
Low distribution rate	1.10%	1.11%
High distribution rate	1.11%	1.19%
Distribution rate at the end of the year	1.11%	1.11%

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 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):

	2014		2013	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Bonds (Level 2)	$ 951,000	$ 1,118,972	$ 951,000	$ 1,054,512

Bonds (Level 3)	402,000	432,728	342,000	329,581
Advances from associated companies (Level 3)	51,547	38,582	51,547	37,114

These estimates of fair value were primarily based on available market information, which generally consists of estimated market prices from third party brokers for debt with similar risk and terms. The price ranges obtained from the third party brokers consisted of par values of 74.85 to 131.21, where a par value of 100.00 represents the carrying value recorded on the Balance Sheets.

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, 2014 and 2013 at fair value on a recurring basis (dollars in thousands):

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
December 31, 2014					
Assets:					
Energy commodity derivatives	$ —	$ 96,729	$ —	$ (95,204)	$ 1,525
Level 3 energy commodity derivatives:					
Natural gas exchange agreements	—	—	1,349	(1,349)	—
Foreign currency derivatives	—	1	—	(1)	—
Interest rate swaps	—	966	—	(506)	460
Deferred compensation assets:					
Fixed income securities (2)	1,793	—	—	—	1,793
Equity securities (2)	6,074	—	—	—	6,074
Total	$ 7,867	$ 97,696	$ 1,349	$ (97,060)	$ 9,852
Liabilities:					
Energy commodity derivatives	$ —	$ 127,094	$ —	$ (110,714)	$ 16,380
Level 3 energy commodity derivatives:					
Natural gas exchange agreement	—	—	1,384	(1,349)	35
Power exchange agreement	—	—	23,299	—	23,299
Power option agreement	—	—	424	—	424
Interest rate swaps	—	77,568	—	(29,386)	48,182
Foreign currency derivatives	—	21	—	(1)	20
Total	$ —	$ 204,683	$ 25,107	$ (141,450)	$ 88,340

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral 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 (2)	1,960	—	—	—	1,960
Equity securities (2)	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

(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 $0.8 million as of December 31, 2014 and $0.7 million as of December 31, 2013.

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 2015, and 3) volatility rates for periods beyond December 2017. 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.

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, 2014 (dollars in thousands):

	Fair Value (Net) at December 31, 2014	Valuation Technique	Unobservable Input	Range
Power exchange agreement	$ (23,299)	Surrogate facility pricing	O&M charges	$30.66-$55.56/MWh (1)
			Escalation factor	3% - 2015 to 2019
			Transaction volumes	184,077 - 397,116 MWhs
Power option agreement	(424)	Black-Scholes-Merton	Strike price	$41.20/MWh - 2015
				$64.09/MWh - 2019
			Delivery volumes	157,517 - 287,147 MWhs
			Volatility rates	0.20 (2)
Natural gas exchange agreement	(35)	Internally derived weighted average cost of gas	Forward purchase prices	$2.32 - $2.57/mmBTU
			Forward sales prices	$2.56 - $3.53/mmBTU
			Purchase volumes	280,000 - 310,000 mmBTUs
			Sales volumes	279,990 - 365,118 mmBTUs

(1) The average O&M charges for the delivery year beginning in November 2014 were $42.90 per MWh. For ratemaking purposes the average O&M charges to be included for recovery in retail rates vary slightly between regulatory jurisdictions. The average O&M

charges for the delivery year beginning in 2014 were $43.11 for Washington and $42.90 for Idaho.
(2) The estimated volatility rate of 0.20 is compared to actual quoted volatility rates of 0.45 for 2015 to 0.21 in December 2017.

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, significant inputs and 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, 2014:				
Balance as of January 1, 2014	$ (1,219)	$ (14,441)	$ (775)	$ (16,435)
Total gains or losses (realized/unrealized):				
Included in net income	—	—	—	—
Included in other comprehensive income	—	—	—	—
Included in regulatory assets/liabilities (1)	3,873	(10,002)	351	(5,778)
Purchases	—	—	—	—
Issuance	—	—	—	—
Settlements	(2,689)	1,144	—	(1,545)
Transfers to/from other categories	—	—	—	—
Ending balance as of December 31, 2014	$ (35)	$ (23,299)	$ (424)	$ (23,758)
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 from other categories	—	—	—	—
Ending balance as of December 31, 2013	$ (1,219)	$ (14,441)	$ (775)	$ (16,435)

(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,
- the hydroelectric licensing requirements of section 10(d) of the FPA (see Note 1), and.
- certain requirements under the OPUC approval of the AERC acquisition. After the initial year, the OPUC does not permit one-time or special dividends from AERC to Avista Corp. and does not permit Avista Corp.'s total equity to total capitalization to be less than 40 percent, without approval from the OPUC. However, the OPUC approval does allow for regular distributions of AERC earnings to Avista Corp. as long as AERC remains sufficiently capitalized and insured.

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

	2014	2013
Dividends paid per common share	$ 1.27	$ 1.22

Under the covenant applicable to the Company's committed line of credit agreement, which does not permit the ratio of "consolidated total debt" to "consolidated total capitalization" to be greater than 65 percent at any time, the amount of retained earnings available for dividends at December 31, 2014 was limited to approximately $295.0 million.

Under the requirements of the OPUC approval of the AERC acquisition as outlined above, the amount available for dividends at December 31, 2014 was limited to approximately $145.0 million.

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 2014 and 2013 and as of December 31, 2014, the Company had 1,795,199 shares available to be issued under these agreements.

The Company has 10 million authorized shares of preferred stock. The Company did not have any preferred stock outstanding as of December 31, 2014 and 2013.

Stock Repurchase Programs

On June 13, 2014, Avista Corp.'s Board of Directors approved a program to repurchase up to 4 million shares of the Company's outstanding common stock, assuming the closure of the Ecova transaction (2014 program). Repurchases of common stock under this program commenced on July 7, 2014 and the program expired on December 31, 2014. Repurchases were made in the open market or in privately negotiated transactions. Through December 31, 2014, the Company repurchased 2,529,615 shares at a total cost of $79.9 million and an average cost of $31.57 per share. The Company did not make any repurchases under this program subsequent to October 2014. All repurchased shares reverted to the status of authorized but unissued shares.

On December 16, 2014, Avista Corp.'s Board of Directors approved the repurchase of up to 800,000 shares of the Company's outstanding common stock, commencing on January 2, 2015, and continuing through March 31, 2015 (first quarter 2015 program). The number of shares repurchased through the first quarter 2015 program is in addition to the number of shares repurchased under the 2014 program, which expired on December 31, 2014. The parameters of the first quarter 2015 program are consistent with the parameters of the 2014 program. All repurchased shares, if any, will revert to the status of authorized but unissued shares.

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, 2014, 0.4 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, 2014, 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):

	2014	2013
Stock-based compensation expense	$ 6,007	$ 5,037
Income tax benefits	2,102	1,763

Stock Options

There are no longer any stock options outstanding as of December 31, 2014 and the Company does not have any plans to issue additional stock options in the near future.

The following summarizes stock options activity under the 1998 Plan and the 2000 Plan for the year ended December 31, 2013:

	2013
Number of shares under stock options:	
Options outstanding at beginning of year	3,000
Options granted	—
Options exercised	(3,000)
Options canceled	—

Options outstanding and exercisable at end of year		—
Weighted average exercise price:		
Options exercised	$	12.41
Options canceled	$	—
Options outstanding and exercisable at end of year	$	—
Cash received from options exercised (in thousands)	$	37
Intrinsic value of options exercised (in thousands)	$	40
Intrinsic value of options outstanding (in thousands)	$	—

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, 2014 was 0.7 years.

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

	2014	2013
Unvested shares at beginning of year	104,416	117,118
Shares granted	62,075	44,556
Shares canceled	(1,550)	(1,802)
Shares vested	(52,899)	(55,456)
Unvested shares at end of year	112,042	104,416
Weighted average fair value at grant date	$ 28.37	$ 26.04
Unrecognized compensation expense at end of year (in thousands)	$ 1,349	$ 1,199
Intrinsic value, unvested shares at end of year (in thousands)	$ 3,961	$ 2,943
Intrinsic value, shares vested during the year (in thousands)	$ 1,473	$ 1,363

Performance and Market-Based Awards

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

Both types of awards entitle the grantee to shares of Avista Corp. common stock or cash payable once the service condition is satisfied and provided that the market or performance conditions are achieved. All TSR awards granted have two conditions, the service condition of three years and a market-based condition, which is the Company's TSR performance over a three-year period as compared against other utilities. CEPS awards began in 2014 and they also have two conditions, the service condition of three years and a performance condition, which is the Company's CEPS performance over a three-year period. CEPS is a performance condition based solely on internal metrics and it is used to determine whether an award vests or not. The level of payout for both the TSR and CEPS awards is based on the level of attainment of the market and performance conditions, respectively.

TSR awards 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. CEPS awards are equity awards with a performance condition based solely on internal Company metrics; therefore, compensation cost for these awards is recognized over the requisite service period, provided that the requisite service period is rendered. However, if the CEPS performance metric is not met, all compensation cost for these awards is reversed as these awards are not considered vested.

The Company measures (at the grant date) the estimated fair value of the shares awarded. The fair value of each TSR award was estimated on the date of grant using a statistical model that incorporates the probability of meeting the market targets based on historical returns relative to a peer group. Expected volatility was based on the historical volatility of Avista Corp. common stock over a three-year period. The expected term of the TSR awards 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 estimated fair value of the equity component of CEPS awards was estimated on the date of grant as the share price of Avista Corp. common stock on the date of grant, less the net present value of the estimated dividends over the three-year period. The combined fair value of the equity and dividend components of CEPS awards is equal to the share price of Avista Corp. common stock on the date of grant.

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

	2014	2013
TSR assumptions		
Risk-free interest rate	0.7%	0.4%
Expected life, in years	3	3
Expected volatility	17.9%	19.1%
Dividend yield	4.5%	4.6%
Weighted average grant date fair value (per share)	$ 24.64	$ 23.30
CEPS assumptions		
Weighted average share price on date of grant	$ 28.09	$ —
Annual dividends per share	1.22	—
Risk-free interest rate	0.7%	—
Weighted average grant date fair value of equity component (per share)	$ 24.48	$ —

The weighted average grant date fair value above for TSR awards includes both the equity component and dividend equivalent rights.

The following summarizes TSR and CEPS share activity:

	2014	2013
TSR Awards		
Opening balance of unvested TSR shares	344,684	359,700
TSR shares granted	117,550	175,000
TSR shares canceled	(6,816)	(13,298)
TSR shares vested	(167,584)	(176,718)

Ending balance of unvested TSR shares		287,834		344,684
Intrinsic value of unvested performance shares (in thousands)	$	10,175	$	9,717
Unrecognized compensation expense (in thousands)	$	2,833	$	3,651
CEPS Awards				
Opening balance of unvested CEPS shares		—		—
CEPS shares granted		59,025		—
CEPS shares canceled		(1,008)		—
CEPS shares vested		—		—
Ending balance of unvested CEPS shares		58,017		—
Intrinsic value of unvested performance shares (in thousands)	$	2,051	$	—
Unrecognized compensation expense (in thousands)	$	1,577	$	—

The weighted average remaining vesting period for the Company's TSR shares outstanding as of December 31, 2014 was 1.4 years. The weighted average remaining vesting period for the Company's CEPS shares outstanding as of December 31, 2014 was 2 years. Unrecognized compensation expense as of December 31, 2014 includes only the amount attributable to the equity portion of the awards and will be recognized during 2015 and 2016.

The following summarizes the impact of the market condition on the TSR shares that met the service vesting condition (no CEPS awards vested in 2014):

		2014		2013
TSR shares vested based on service condition		167,584		176,718
Impact of market condition on shares vested		(70,385)		(176,718)
Shares of common stock earned		97,199		—
Intrinsic value of common stock earned (in thousands)	$	3,436	$	—

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

Outstanding TSR and CEPS share awards include a dividend component that is paid in cash. This component of the 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, the change in the value of the Company's common stock relative to an external benchmark (TSR awards only) and the amount of CEPS earned to-date compared to estimated CEPS over the performance period (CEPS awards only). Over the life of these awards, the cumulative amount of compensation expense recognized will match the actual cash paid. As of December 31, 2014 and 2013, the Company had recognized cumulative compensation expense and a liability of $1.3 million and $0.9 million, respectively, related to the dividend component on the outstanding and unvested 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) 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). 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 energy markets operated by the California Independent System Operator (CalISO) and the California Power Exchange (CalPX)(Bidding Investigation). Appeals of the FERC's decisions are pending before the United States Court of Appeals for the Ninth Circuit (Ninth Circuit).

On March 7, 2014, Avista Corp. and Avista Energy filed at FERC a settlement 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 (together, the "California Parties") that resolves both the Trading Investigation and the Bidding Investigation. The settlement was approved by the FERC and is final so there is no longer any potential liability.

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). Petitions for review of the FERC's decisions are still pending in the Ninth Circuit. In August 2006, the Ninth Circuit remanded to the FERC its decision not to consider a Federal Power Act (FPA) section 309 remedy for tariff violations prior to October 2, 2000. During the FERC hearing on the remand in 2012, the Presiding Administrative Law Judge (ALJ) issued a partial initial decision granting Avista Corp.'s motion for summary disposition. On November 2, 2012, the FERC issued an order affirming the partial initial decision and dismissing Avista Corp. from the proceeding. On February 15, 2013, the ALJ issued an Initial Decision that may have subjected Avista Energy to additional refund liability.

On March 7, 2014, Avista Corp., Avista Energy and the California Parties filed a settlement at the FERC that fully resolved these matters. Because Avista Energy had not been paid for all of its sales during the Refund Period, substantial funds have been held in escrow accounts pending resolution of this proceeding. The settlement returned $15.0 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. The settlement funds were received on June 23, 2014 and recorded as a reduction to other operating expenses within the non-utility operating expenses section of the Statements of Income. There is no admission of wrongdoing on the part of the settling parties and no part of the refund payment by Avista Energy constitutes a fine or a penalty. The settlement resolves all claims for alleged overcharges in the California Refund Proceeding, and in the Pacific Northwest Refund Proceeding (for sales made to CERS). The settlement also includes settlement of the Trading Investigation, the Bidding Investigation and the California Attorney General Complaint (the "Lockyer Complaint"). The settlement was approved by the FERC and is final so there is no longer any potential liability.

California Attorney General Complaint (the "Lockyer Complaint")

In May 2002, the FERC 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 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.

On March 7, 2014, Avista Corp., Avista Energy and the California Parties filed a settlement at the FERC that resolves this matter. The settlement was approved by the FERC and is final so there is no longer any potential liability.

Pacific Northwest Refund Proceeding

In July 2001, the Federal Energy Regulatory Commission ("FERC" or "Commission") 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 had failed to take into account new evidence of market manipulation 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 new evidence. The Ninth Circuit expressly declined to direct the FERC to grant refunds. On October 3, 2011, the FERC issued an Order on Remand. 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. 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 would not be sufficient to establish a causal connection between a particular seller's alleged unlawful activities and the specific contract negotiations at issue. The hearing was conducted in August through October 2013. The City of Seattle, Washington (Seattle) and the California AG (on behalf of CERS) filed petitions for review of FERC's Order on Remand in the 9th Circuit Court of Appeals, which petitions were stayed pending completion of the FERC proceeding.

On July 11, 2012 and March 28, 2013, Avista Energy and Avista Corp. filed settlements of all issues in this docket with regard to the claims made by the City of Tacoma and the California AG (on behalf of CERS). The FERC approved the settlements and they are final. The remaining direct claimant against Avista Corp. and Avista Energy in this proceeding is Seattle.

With regard to the Seattle claims, on March 28, 2014, the Presiding ALJ issued her Initial Decision finding that: 1) Seattle failed to demonstrate that either Avista Corp. or Avista Energy engaged in unlawful market activity and also failed to identify any specific contracts at issue; 2) Seattle failed to demonstrate that contracts with either Avista Corp. or Avista Energy imposed an excessive burden on consumers or seriously harmed the public interest; and that 3) Seattle failed to demonstrate that either Avista Corp. or Avista Energy engaged in any specific violations of substantive provisions of the Federal Power Act or any filed tariffs or rate schedules. Accordingly, the ALJ denied all of Seattle's claims under both section 206 and section 309 of the Federal Power Act. Briefs on and opposing exceptions have been filed and the Initial Decision is pending before the FERC.

The 9th Circuit by Order dated February 17, 2015 issued on its own motion, lifted the stay of the 2013 interlocutory petitions for review of the FERC Order on Remand and established a briefing schedule for those petitions, including Seattle's petition challenging the scope of the Remand Order. Any decision by the 9th Circuit adverse to the Company could only result in a further remand to FERC to conduct further proceedings, the scope of which cannot be predicted at this time. The Company does not expect that this matter will have a material adverse effect on 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 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 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 Colstrip.

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. The Colstrip Owners filed a Motion to Dismiss, seeking dismissal of all of Plaintiffs' claims contained in the Amended Complaint.

On May 22, 2014, the Magistrate Judge filed his Findings and Recommendations as to the motions and recommended that 1) the Colstrip Owners' Motion to Dismiss be granted as to the Plaintiffs' Best Available Control Technology claims and the injunctive relief sought regarding two of the claims, but denied the Motion in all other respects; and 2) the Plaintiffs' Motion for Partial Summary Judgment be denied. Plaintiffs' filed Objections to Findings and Recommendations of Magistrate Judge and the Colstrip Owners filed their response to Plaintiffs' objections.

On August 27, 2014, the Plaintiffs filed a Second Amended Complaint. The Second Amended Complaint withdraws from the Amended Complaint five claims and adds one new claim. The Second Amended Complaint alleges certain violations of the Clean Air Act and the New Source Review. The Plaintiffs request that the Court grant injunctive and declaratory relief, order remediation of alleged environmental damages, 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.

The Court has set the trial date for November 2015.

Management believes that it is reasonably possible that this matter could result in a loss to the Company. However, due to uncertainties concerning this matter, Avista Corp. cannot estimate the outcome or determine whether it would have a material impact on the Company.

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. On February 19, 2015, the Court dismissed the case as stipulated to by all parties.

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. The Company obtained regulatory Orders from the UTC and IPUC during the second half of 2013, allowing regulatory treatment of the costs from the discontinued project.

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. Ongoing design improvements have been made, and the Company expects to continue spill crest modifications over the next several years, in ongoing consultation with key stakeholders. 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 United States Fish and Wildlife Service (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.

Kettle Falls Generation Station - Diesel Spill Investigation and Remediation

In December 2013, the Company's operations staff at the Kettle Falls Generation Station discovered that approximately 10,000 gallons of diesel fuel had leaked underground from the piping system used to fuel heavy equipment. Avista Corp. made all proper agency notifications and worked closely with Ecology during the spill response and investigation phase. The Company installed ground water monitoring wells and there is no indication that ground or surface water is threatened by the spill.

There is no indication that Ecology is considering any enforcement action and the Company initiated a voluntary cleanup action with the installation of a recovery system.

As of December 31, 2014, the Company has recorded an estimated remediation liability and the Company will continue to monitor the remediation activities and will adjust any estimated remediation liability if necessary as new information is obtained. The Company does not expect that this matter will have a material effect on its financial condition, results of operations or cash flows.

Collective Bargaining Agreements

The Company's collective bargaining agreements with the IBEW 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 Avista Corp.'s bargaining unit employees expired in March 2014. A new two-year agreement with this group was approved in January 2015 and has an expiration of March 2016. A new three-year agreement in Oregon, which covers approximately 50 employees, was approved in April 2014.

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 or AEL&P'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):

	2014	2013
Information service contract payments	$ 13,022	$ 12,647

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):

	2015	2016	2017	2018	2019	Thereafter	Total
Contractual obligations	$ 9,047	$ 9,141	$ 9,237	$ —	$ —	$ —	$ 27,425

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), and
- retail loads.

In Washington, the 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 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 $14.2 million as of December 31, 2014, 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 there was a one-year credit designed to return to customers $4.4 million from the existing ERM deferral balance which reduced the net average electric rate increase impact to customers in 2013. Additionally, during 2014 there was a one-year credit designed to return $9.0 million to electric customers from the ERM deferral balance, so the net average electric rate increase impact to customers effective January 1, 2014 was also 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 $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:

	Deferred for Future Surcharge or Rebate	Expense or Benefit

Annual Power Supply Cost Variability	to Customers	
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%

Avista Corp. has a PCA mechanism in Idaho that allows it to modify electric rates on October 1 of each year with IPUC approval. Under the PCA mechanism, Avista Corp. defers 90 percent of the difference between certain actual net power supply expenses and the amount included in base retail rates for its Idaho customers. 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 $8.3 million as of December 31, 2014 compared to a regulatory asset of $5.1 million as of December 31, 2013.

Natural Gas Cost Deferrals and Recovery Mechanisms

Avista Corp. files a PGA in all three states it serves to adjust natural gas rates for: 1) estimated commodity and pipeline transportation costs to serve natural gas customers for the coming year, and 2) the difference between actual and estimated commodity and transportation costs for the prior year. 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 $3.9 million as of December 31, 2014 compared to a liability of $12.1 million as of December 31, 2013.

Washington General Rate Cases

2012 General Rate Cases

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 increased 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 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, base rates increased 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 provided for a one-year credit designed to return $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 did not impact the Company's earnings. The ERM balance as of December 31, 2014 was a liability of $14.2 million.

The settlement agreement provided 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 that became effective on January 1, 2014 were temporary rates, and on January 1, 2015, electric and

natural gas base rates were scheduled to revert back to 2013 levels absent any intervening action from the UTC. The original settlement agreement had a provision that the Company would not file a general rate case in Washington seeking new rates to take effect before January 1, 2015. In November 2014, the UTC approved a settlement agreement to the Company's Washington general rate cases which were originally filed in February 2014 with rates effective on January 1, 2015 (see further discussion below).

(2) In its Order, the UTC found that much of the approved base rate increase was 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. The Company 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. Total utility capital expenditures among all jurisdictions were $294.4 million and $323.9 million for 2013 and 2014 respectively. The Company expects utility capital expenditures to be about $375 million for 2015 and $350 million in 2016, which are above the capital expenditures contemplated in the settlement agreement.

2014 General Rate Cases

In November 2014, the UTC approved an all-party settlement agreement related to the Company's electric and natural gas general rate cases filed in February 2014 and new rates became effective on January 1, 2015. The settlement is designed to increase annual electric base revenues by $12.3 million, or 2.5 percent, inclusive of a $5.3 million power supply update as required in the settlement agreement (explained below). The settlement is designed to increase annual natural gas base revenues by $8.5 million, or 5.6 percent.

Expiring and New Rebates and ERM

The parties agreed in the settlement that a credit of $8.3 million (including the $5.3 million power supply update) from the ERM deferral balance will be returned to electric customers to help offset the 2015 rate increase. This ERM balance represents lower net power supply costs in recent years than the costs embedded in base retail rates, which are being returned to customers in the form of a rebate. This rebate will not increase or decrease the Company's net income. Total net deferred power costs under the ERM were a liability of $14.2 million as of December 31, 2014, compared to a liability of $17.9 million as of December 31, 2013, and these deferred power cost balances represent amounts due to customers.

In addition, the Company's electric customers were receiving benefits from two rebates that expired at the end of 2014 and which reduced monthly energy bills by 2.8 percent during 2014. The parties agreed in the settlement that the Company will provide a rebate to customers of $8.6 million over an 18 month period related to the sale of renewable energy credits, which will partially replace the expiring rebates and reduce customers' monthly bills by 1.2 percent, beginning January 1, 2015. The net effect of the expiring rebates and the new rebate will result in an increase of approximately 1.6 percent beginning January 1, 2015. These rebates are passed through to customers and do not increase or decrease the Company's net income.

The overall change in customer billing rates from the approved settlement agreement, including the expiring and new rebates, is 2.5 percent for electric customers and 5.6 percent for natural gas customers effective January 1, 2015.

Power Supply Update and Customer Information and Work Management Systems Deferral

The settlement agreement included a provision that required the Company to update base power supply costs on November 1, 2014. This update to power supply costs was reflected in the overall electric revenue increase effective January 1, 2015, and reset the base power supply costs for the ERM calculations effective January 1, 2015. The amount of the updated power supply costs was a $5.3 million increase. The increase to customers from the power supply update was offset with the available ERM deferral balance for the calendar year 2015. The use of the ERM deferral balance for the offset will not increase or decrease the Company's net income.

The parties also agreed that the natural gas revenue requirement associated with the Company's investment in the Customer

Information and Work Management Systems capital project (Project Compass) for 2015 will be deferred for regulatory purposes for recovery in retail rates through a future general rate case, based on the actual costs of the project at the time it goes into service. Project Compass went into service in February 2015. The future recovery of these costs and return on investment, estimated to be $2.0 million on a pre-tax basis, will be recognized in the future recovery period.

Decoupling

The parties agreed that the Company will implement electric and natural gas decoupling mechanisms for a five-year period beginning January 1, 2015. Decoupling is a mechanism designed to sever the link between a utility's revenues and consumers' energy usage. The Company's actual revenue, based on kilowatt hour and therm sales will vary, up or down, from the level established in a general rate case. This could be due to changes in weather, conservation or the economy. Per the terms of the settlement agreement and the decoupling mechanisms included therein, generally, electric and natural gas revenues will be adjusted each month to be based on the number of customers, rather than kilowatt hour and therm sales. The difference between revenues based on sales, and revenues based on the number of customers will be deferred and either surcharged or rebated to customers beginning in the following year. Electric and natural gas decoupling surcharge rate adjustments to customers are limited to 3 percent on an annual basis, with any remaining surcharge balance carried forward for recovery in a future period. There is no limit on the level of rebate rate adjustments.

The decoupling mechanisms each include an after-the-fact earnings test. At the end of each calendar year, separate electric and natural gas earnings calculations will be made for the prior calendar year. These earnings tests will reflect actual decoupled revenues, normalized power supply costs, and other normalizing adjustments.

- If there is a decoupling rebate balance for the prior year and Avista Corp. earns in excess of a 7.32 percent rate of return (ROR), the rebate to customers would be increased by 50 percent of the earnings in excess of the 7.32 percent ROR.
- If there is a decoupling rebate balance for the prior year and Avista Corp. earns a 7.32 percent ROR or less, only the base amount of the rebate to customers would be made.
- If there is a decoupling surcharge balance for the prior year and Avista Corp. earns in excess of a 7.32 percent ROR, the surcharge to customers would be reduced by 50 percent of the earnings in excess of the 7.32 percent ROR (or eliminated).
- If there is a decoupling surcharge balance for the prior year and Avista Corp. earns a 7.32 percent ROR or less, the base amount of the surcharge to customers would be made.

Original Request

The Company's original request filed with the UTC in February 2014 included a base electric rate increase of 3.8 percent (designed to increase annual electric revenues by $18.2 million). The Company also requested a base natural gas rate increase of 8.1 percent (designed to increase annual natural gas revenues by $12.1 million). Specific capital structure ratios and the cost of capital components were not agreed to in the settlement agreement, and the revenue increases in the settlement were not tied to the 7.32 percent ROR referenced above. The electric and natural gas revenue increases were negotiated numbers, with each party using its own set of assumptions underlying its agreement to the revenue increases. The parties agreed that the 7.32 percent ROR will be used to calculate the Allowance for Funds Used During Construction (AFUDC) and other purposes.

2015 General Rate Cases

In February 2015, 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 6.6 percent (designed to increase annual electric revenues by $33.2 million) and an overall increase in base natural gas rates of 7.0 percent (designed to increase annual natural gas revenues by $12.0 million). The Company's requests are based on a proposed ROR on rate base of 7.46 percent with a common equity ratio of 48 percent and a 9.9 percent return on equity.

The major driver of these general rate case requests is to recover the costs associated with the ongoing need to maintain, replace and invest in the Company's facilities and equipment. Several significant capital investments the Company has made and is currently making, that are included in the filing are:

- the ongoing and multi-year redevelopment of the Little Falls Powerhouse on the Spokane River,
- the continuing rehabilitation of the Nine Mile Powerhouse on the Spokane River,
- information technology upgrades that include the replacement of the Company's customer information and work management systems (which were implemented in February 2015),
- the ongoing project to systematically replace portions of Aldyl-A natural gas distribution pipe, and
- technology investments for deploying Advanced Metering Infrastructure in Washington, including installation of advanced meters, beginning in 2016.

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

Idaho General Rate Cases

2012 General Rate Cases

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 was 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 was 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 did not impact the Company's net income.

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

The settlement also included 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 share with customers 50 percent of any earnings above the 9.8 percent. In 2013, the Company's returns exceeded this level and $3.9 million was deferred for future ratemaking treatment for Idaho electric customers and $0.4 million for Idaho natural gas customers. Of the electric deferral amount, $2.0 million was recorded in 2013 and $1.9 million was recorded in the first quarter of 2014 based on a revision of the allocation of costs between Idaho and Washington for regulatory purposes. The ratemaking treatment for these deferrals is addressed in the 2014 rate plan extension request explained below.

In 2014, the Company's returns exceeded a 9.8 percent return on equity and the Company deferred for future ratemaking treatment

$7.5 million (including the $1.9 million related to 2013 that was recorded in 2014) for Idaho electric customers and $0.2 million for Idaho natural gas customers. The period over which these amounts will be returned to customers has not yet been determined by the IPUC.

2014 Rate Plan Extension

The Company did not file new general rate cases in Idaho in 2014, instead, it developed an extension to the 2013 and 2014 rate plan and reached a settlement agreement with all interested parties.

In September 2014, the IPUC approved the settlement, which reflects agreement among all interested parties, for a one-year extension to the current rate plan, which was set to expire on December 31, 2014. Under the approved extension, base retail rates will remain unchanged through December 31, 2015.

The settlement will provide an estimated $3.7 million increase in pre-tax income by reducing planned expenses in 2015 for Idaho operations, resulting from:

- the delay of the beginning of the amortization of the 2013 previously deferred operations and maintenance costs pertaining to the Colstrip and Coyote Springs 2 thermal generating facilities from 2015 to 2016, and
- deferred accounting, for later review and recovery, of the majority of the costs associated with Project Compass, which was implemented in February 2015.

The settlement agreement establishes an ROE deadband between the currently authorized ROE of 9.8 percent and a 9.5 percent ROE. Under the settlement agreement, the Company will be allowed to use any 2014 Idaho after-the-fact earnings test deferral (described above under "2012 General Rate Cases") to support an actual earned ROE in 2015 up to 9.5 percent. For 2014, the Company deferred a total of $7.7 million for the 2014 after-the-fact earnings test, which includes the $1.9 million recorded in 2014 related to the 2013 earnings test. During 2015, if the Company earns more than the 9.8 percent ROE, 50 percent of the earnings above 9.8 percent will be shared with customers through future ratemaking.

As part of the settlement, the Company agreed not to file a general rate case in 2014, and would file no earlier than May 31, 2015 for new electric or natural gas base retail rates to become effective on or after January 1, 2016. In addition, the settlement replaced two rebates, which expired on January 1, 2015, that were reducing customers' monthly energy bills by 1.3 percent for electric and 1.7 percent for natural gas. The rebates were replaced for a one-year period, through December 31, 2015, using existing deferral balances due to customers, which will have no impact on the Company's net income. This provision does not preclude the filing of other rate adjustments such as the PGA.

Oregon General Rate Cases

2013 General Rate Case

In January 2014, the 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 were 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 $3.8 million). Effective November 1, 2014, rates for Oregon natural gas customers were to increase on a billed basis by an overall 1.6 percent (designed to increase annual revenues by $1.4 million).

The billed rate increase on November 1, 2014 was dependent upon the completion of Project Compass and the actual costs incurred through September 30, 2014, and the actual costs incurred through June 30, 2014 related to the Company's Aldyl A distribution pipeline replacement program. As noted elsewhere, Project Compass was completed in February 2015. The November 1, 2014 rate increase was reduced from $1.4 million to $0.3 million due to the delay of Project Compass.

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.

2014 General Rate Case

In January 2015, the Company filed an all-party settlement agreement with the OPUC related to the Company's natural gas general rate case, which was originally filed in September 2014. The settlement agreement was designed to increase base natural gas revenues by 6.1 percent or $6.1 million. This base rate increase was offset by $0.3 million for a separate rate adjustment that the Company is already receiving from customers and it was offset by a $0.8 million credit to customers related to having an early implementation date for the revenue increase (prior to the full 10 months allowed in Oregon for the OPUC to make a decision on the case and new rates to take effect). The net increase to the Company after the two offsets was $5.0 million. The parties to the settlement agreement had requested a decision from the OPUC prior to March 1, 2015, such that new retail rates could be effective on March 1, 2015.

This settlement agreement provided for an overall authorized rate of return of 7.52 percent with a common equity ratio of 51 percent and a 9.5 percent return on equity.

The original request was for an overall increase in base natural gas rates of 9.3 percent (designed to increase annual natural gas revenues by $9.1 million) and it was based on a proposed rate of return of 7.77 percent with a common equity ratio of 51 percent and a 9.9 percent return on equity.

On February 23, 2015, the OPUC issued an order rejecting the all-party settlement agreement filed with the OPUC by the parties on January 21, 2015. The OPUC expressed concerns related to three issues: 1) the proposed early rate implementation credit; 2) the combination of proposed rate increases and rate decreases across the customer classes (rate spread); and 3) the customer count tracking mechanism. With regard to the early rate implementation credit, the order stated, among other things, that there was no evidence in the record that explains the derivation of the rate credit amount, or why the credit would be applied to all customer classes. On rate spread, the OPUC's order expressed concern about proposed increases to rates for some customer classes, and decreases for other customer classes, absent more compelling evidence. And finally, the OPUC expressed concern that the customer count tracking mechanism is contrary to standard ratemaking.

The OPUC's order directed the Administrative Law Judge to convene a prehearing conference to schedule further proceedings in a manner that will allow for the timely completion of the case. The OPUC's order also encouraged the parties to come back with a partial stipulation that encompasses these issues. Furthermore, the OPUC stated that its order does not preclude the parties from reaching a global settlement of all issues that addresses the concerns identified by the OPUC.

Bonneville Power Administration Reimbursement and Reardan Wind Generation Project

In May 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 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 were allocable to the Washington business, leaving $5.1 million to be retained for the benefit of shareholders.

The BPA agreed to pay $3.2 million annually for the future use of Avista Corp.'s transmission system. The Company separately tracked and deferred 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) was 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):

	2014	2013
Cash paid for interest	$69,693	$70,444
Cash paid for income taxes	$41,154	$42,497

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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	04/15/2015	End of 2014/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	167,261	(6,867,421)		
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	(12,411)			
3	Preceding Quarter/Year to Date Changes in Fair Value	(1,740,705)	2,633,346		
4	Total (lines 2 and 3)	(1,753,116)	2,633,346		
5	Balance of Account 219 at End of Preceding Quarter/Year	(1,585,855)	(4,234,075)		
6	Balance of Account 219 at Beginning of Current Year	(1,585,855)	(4,234,075)		
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	460,497			
8	Current Quarter/Year to Date Changes in Fair Value	1,125,358	(3,653,806)		
9	Total (lines 7 and 8)	1,585,855	(3,653,806)		
10	Balance of Account 219 at End of Current Quarter/Year		(7,887,881)		

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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			(6,700,160)		
2			(12,411)		
3			892,641		
4			880,230	111,076,833	111,957,063
5			(5,819,930)		
6			(5,819,930)		
7			460,497		
8			(2,528,448)		
9			(2,067,951)	192,040,688	189,972,737
10			(7,887,881)		

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	04/15/2015	End of 2014/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)	4,501,741,499	3,325,688,469
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)	4,508,183,848	3,325,688,469
9	Leased to Others		
10	Held for Future Use	4,964,376	4,773,791
11	Construction Work in Progress	223,330,993	112,974,359
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	4,736,479,217	3,443,436,619
14	Accum Prov for Depr, Amort, & Depl	1,573,767,832	1,196,318,690
15	Net Utility Plant (13 less 14)	3,162,711,385	2,247,117,929
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	1,531,197,363	1,181,974,217
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	42,570,469	14,344,473
22	Total In Service (18 thru 21)	1,573,767,832	1,196,318,690
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)	1,573,767,832	1,196,318,690

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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
889,870,069				286,182,961	3
858,864				5,583,485	4
					5
					6
					7
890,728,933				291,766,446	8
					9
190,585					10
11,625,968				98,730,666	11
					12
902,545,486				390,497,112	13
298,791,678				78,657,464	14
603,753,808				311,839,648	15
					16
					17
296,850,488				52,372,658	18
					19
					20
1,941,190				26,284,806	21
298,791,678				78,657,464	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
298,791,678				78,657,464	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	04/15/2015	End of 2014/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	6,013,233	11,692,168
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	50,665,155	11,692,168
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	3,489,809	88,363
9	(311) Structures and Improvements	127,428,055	877,207
10	(312) Boiler Plant Equipment	166,292,927	3,825,217
11	(313) Engines and Engine-Driven Generators	6,770	
12	(314) Turbogenerator Units	52,977,820	3,696,502
13	(315) Accessory Electric Equipment	26,565,246	641,899
14	(316) Misc. Power Plant Equipment	16,361,137	639,155
15	(317) Asset Retirement Costs for Steam Production	585,275	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	393,707,039	9,768,343
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	58,280,857	1,455,242
28	(331) Structures and Improvements	46,380,994	10,420,842
29	(332) Reservoirs, Dams, and Waterways	131,438,434	6,495,601
30	(333) Water Wheels, Turbines, and Generators	162,974,778	4,867,334
31	(334) Accessory Electric Equipment	37,295,984	1,180,965
32	(335) Misc. Power PLant Equipment	9,220,102	112,388
33	(336) Roads, Railroads, and Bridges	2,341,039	332,779
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	447,932,188	24,865,151
36	D. Other Production Plant		
37	(340) Land and Land Rights	905,167	
38	(341) Structures and Improvements	16,766,676	2,230
39	(342) Fuel Holders, Products, and Accessories	21,174,046	126,752
40	(343) Prime Movers	23,909,470	
41	(344) Generators	205,252,241	296,836
42	(345) Accessory Electric Equipment	20,344,543	504,398
43	(346) Misc. Power Plant Equipment	1,494,484	31,232
44	(347) Asset Retirement Costs for Other Production	351,683	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	290,198,310	961,448
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,131,837,537	35,594,942

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

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
343,665			17,361,736		4
343,665			62,013,658		5
					6
					7
			3,578,172		8
69,920			128,235,342		9
2,302,189			167,815,955		10
			6,770		11
3,150,633			53,523,689		12
62,599			27,144,546		13
10,679			16,989,613		14
			585,275		15
5,596,020			397,879,362		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			59,736,099		27
91,879			56,709,957		28
76,909			137,857,126		29
60,974			167,781,138		30
395,906			38,081,043		31
24,773			9,307,717		32
			2,673,818		33
					34
650,441			472,146,898		35
					36
			905,167		37
			16,768,906		38
			21,300,798		39
			23,909,470		40
			205,549,077		41
135,390			20,713,551		42
1,262			1,524,454		43
			351,683		44
136,652			291,023,106		45
6,383,113			1,161,049,366		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	04/15/2015	End of 2014/Q4

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	19,177,807	385,536
49	(352) Structures and Improvements	19,293,831	1,308,431
50	(353) Station Equipment	220,819,229	17,008,640
51	(354) Towers and Fixtures	17,124,556	969
52	(355) Poles and Fixtures	163,844,864	16,514,290
53	(356) Overhead Conductors and Devices	120,207,906	5,415,068
54	(357) Underground Conduit	2,838,390	134,633
55	(358) Underground Conductors and Devices	2,331,360	-1,288
56	(359) Roads and Trails	1,949,859	2,016
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	567,587,802	40,768,295
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	7,018,762	352,117
61	(361) Structures and Improvements	18,203,061	695,465
62	(362) Station Equipment	115,922,437	7,371,945
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	280,550,075	27,893,938
65	(365) Overhead Conductors and Devices	187,950,468	10,207,738
66	(366) Underground Conduit	88,448,037	3,550,324
67	(367) Underground Conductors and Devices	150,615,842	9,927,773
68	(368) Line Transformers	207,666,199	11,857,514
69	(369) Services	137,573,730	5,315,227
70	(370) Meters	47,958,233	1,034,174
71	(371) Installations on Customer Premises		
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	39,127,438	1,338,612
74	(374) Asset Retirement Costs for Distribution Plant	129,707	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,281,163,989	79,544,827
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	398,664	
87	(390) Structures and Improvements	6,780,117	197,179
88	(391) Office Furniture and Equipment	8,081,480	1,291,134
89	(392) Transportation Equipment	23,019,835	7,554,037
90	(393) Stores Equipment	395,329	
91	(394) Tools, Shop and Garage Equipment	3,014,968	106,128
92	(395) Laboratory Equipment	714,946	95,433
93	(396) Power Operated Equipment	39,156,402	-3,431,389
94	(397) Communication Equipment	52,859,207	5,342,259
95	(398) Miscellaneous Equipment	57,117	23,780
96	SUBTOTAL (Enter Total of lines 86 thru 95)	134,478,065	11,178,561
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)	134,478,065	11,178,561
100	TOTAL (Accounts 101 and 106)	3,165,732,548	178,778,793
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)	3,165,732,548	178,778,793

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	04/15/2015	End of 2014/Q4

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
			19,563,343		48
118,869			20,483,393		49
5,045,898			232,781,971		50
			17,125,525		51
648,732			179,710,422		52
101,850			125,521,124		53
			2,973,023		54
			2,330,072		55
			1,951,875		56
					57
5,915,349			602,440,748		58
					59
1,991		-13,614	7,355,274		60
47,697			18,850,829		61
709,593			122,584,789		62
					63
1,339,893			307,104,120		64
204,213			197,953,993		65
34,916			91,963,445		66
360,901			160,182,714		67
134,902			219,388,811		68
49,347			142,839,610		69
769,440			48,222,967		70
					71
					72
121,568			40,344,482		73
			129,707		74
3,774,461		-13,614	1,356,920,741		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			398,664		86
15,705		483,555	7,445,146		87
443,367			8,929,247		88
532,566		33,876	30,075,182		89
			395,329		90
113,282			3,007,814		91
132,717			677,662		92
1,160,688			34,564,325		93
511,776			57,689,690		94
			80,897		95
2,910,101		517,431	143,263,956		96
					97
					98
2,910,101		517,431	143,263,956		99
19,326,689		503,817	3,325,688,469		100
					101
					102
					103
19,326,689		503,817	3,325,688,469		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	04/15/2015	End of 2014/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				
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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	04/15/2015	End of 2014/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	36,964,705
2	Clark Fork Implement PME Agreement	14,907,484
3	Little Falls Powerhouse Redevelopment	12,426,195
4	Post Falls S Channel Gate REplacement	7,718,986
5	Cabinet Gorge HED U#1 Refurbishment	6,769,449
6	Noxon 230 kV Substation - Rebuild	4,597,542
7	Spokane River Implementation (PM&E)	3,196,307
8	Mobile Substation - Purchase New Mobile Subs	2,470,957
9	Dis Grid Modernization	2,457,596
10	Regulating Hydro	1,667,115
11	Kettle Falls Develop New River Wells	1,525,172
12	Transportation Equip	1,448,367
13	Opportunity 115 kV Switching Station	1,099,013
14	Minor Projects <$1M	15,959,979
15		
16	Research, Development, and Demonstrating:	
17	SGDP-Pullmand Smart Grid Demonstration Project	150,974
18	Battery Storage - Distribution (net of Grant reimbursements)	-385,482
19		
20		
21		
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43	TOTAL	112,974,359

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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	1,123,890,020	1,123,890,020		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	77,951,605	77,951,605		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	4,861,553	4,861,553		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	-283,998	-283,998		
9	Transfer	25,343	25,343		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	82,554,503	82,554,503		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	18,981,034	18,981,034		
13	Cost of Removal	3,103,899	3,103,899		
14	Salvage (Credit)	53,026	53,026		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	22,031,907	22,031,907		
16	Other Debit or Cr. Items (Describe, details in footnote):	-2,438,399	-2,438,399		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,181,974,217	1,181,974,217		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	279,829,852	279,829,852		
21	Nuclear Production				
22	Hydraulic Production-Conventional	130,519,156	130,519,156		
23	Hydraulic Production-Pumped Storage				
24	Other Production	90,174,918	90,174,918		
25	Transmission	193,042,242	193,042,242		
26	Distribution	427,080,299	427,080,299		
27	Regional Transmission and Market Operation				
28	General	61,327,750	61,327,750		
29	TOTAL (Enter Total of lines 20 thru 28)	1,181,974,217	1,181,974,217		

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

Includes:

Reverse 12/31/2013 Ending Balance miscellaneous adjustment of $15,219
ARO 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: b

Includes: Change in Removal Work in Progress $-2,438,399

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	04/15/2015	End of 2014/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		206,225,548
3	Avista Capital - Equity in Earnings			-98,061,002
4	OCI Investment in Subs			-1,585,855
5	Avista Capital - Other Changes in Net Investment			5,653,413
6	Alaska - Equity in Earnings			
7				
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42	Total Cost of Account 123.1 $ 0		TOTAL	112,232,104

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	04/15/2015	End of 2014/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
	-86,577	206,138,971		2
79,182,513	-130,000,213	-148,878,702		3
	1,585,855			4
	-5,653,413			5
3,179,202	87,816,380	90,995,582		6
				7
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82,361,715	-46,337,968	148,255,851		42

Schedule Page: 224 Line No.: 6 Column: f

$87,816,380 revenue from Alaska consists of:

($67,000,000) Dividends received
$154,816,380 Acquisition Costs

Total shares issued 4,501,441

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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) 04/15/2015	Year/Period of Report End of 2014/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)	3,170,050	4,116,727	(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)	17,104,229	17,901,172	(1)
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	2,721,461	2,752,174	(1)
8	Transmission Plant (Estimated)	166,825	122,300	(1)
9	Distribution Plant (Estimated)	316,067	359,649	(1)
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	6,347,128	8,284,177	(1),(2)
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	26,655,710	29,419,472	
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)	29,825,760	33,536,199	

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

(1) Electric

(2) Natural 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	04/15/2015	End of 2014/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**				
2					
3					
4					
5					
6					
7					
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9					
10					
11					
12					
13					
14					
15					
16					
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20					
21	**Generation Studies**				
22	AVA Nine Mile Upgrade	6,710	186200		
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Schedule Page: 231 Line No.: 22 Column: a

Total life to date costs.

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	04/15/2015	End of 2014/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	156,984,296	78,773,807			235,758,103
2	Regulatory Asset FAS109 Utility Plant	62,885,005		283	18,111,883	44,773,122
3	Regulatory Asset Lancaster Generation	2,606,667		407	1,360,000	1,246,667
4	Regulatory Asset FAS109 DSIT Non Plant	1,257,594	46,765,187			48,022,781
5	Regulatory Asset FAS109 DFIT State Tax Cr	3,182,069	1,056,543			4,238,612
6	Regulatory Asset FAS109 WNP3	4,178,855		283	737,482	3,441,373
7	Regulatory Asset- Spokane River Relicense	543,626		407	78,736	464,890
8	Regulatory Asset- Spokane River PM&E	502,574		557	73,312	429,262
9	Regulatory Asset- Lake CDA Fund	9,226,534		407	211,065	9,015,469
10	Regulatory Asset- Lake CDA IPA Fund	2,000,000				2,000,000
11	Regulatory Asset- Spokane River TDG Idaho	468,893				468,893
12	Reg Assets- Decouplings Surcharge	7,566		242	2,106	5,460
13	Regulatory Asset- Lake CDA DEF Costs	1,310,141		407	32,719	1,277,422
14	Regulatory Asset BPA Residential Exchange	1,105,802		283	1,105,802	
15	Regulatory Asset- CNC Transmission	230,632		407	230,632	
16	DEF CS2 & COLSTRIP	5,813,051		407	8,738	5,804,313
17	LiDAR O&M REG DEF	67,365		407	67,365	
18	Reardan Wind Generation	852,642		407	682,113	170,529
19	ID Wind Gen AFUDC	230,858		407	184,687	46,171
20	Regulatory Asset Wartsila Units	414,029		407	260,873	153,156
21	MTM St Regulatory Asset	10,829,415	18,810,959			29,640,374
22	MTM Lt Regulatory Asset	23,257,565	1,225,610			24,483,175
23	Regulatory Asset FAS143 Asset Retirement Obligation	2,110,232	191,021			2,301,253
24	Reg Asset AN- CDA Lake Settlement	35,400,262		407	884,086	34,516,176
25	Reg Asset WA-CDA Lake Settlement	1,052,152		407	152,118	900,034
26	Regulatory Asset Workers Comp	2,486,931		407	292,588	2,194,343
27	CS2 Lev Ret	408,999		407	408,999	
28	Regulatory Asset ID PCA Deferral 2	5,065,235	6,211,802	557	5,065,235	6,211,802
29	Regulatory Asset ID PCA Deferral 3		2,078,991	557		2,078,991
30	Spokane RIver TDG	871,184				871,184
31	Interest Rate Swap Asset	36,525,856		407	2,561,321	33,964,535
32	DSM Asset	9,576,204	4,603,418	407	9,576,207	4,603,415
33	SWAPS ON FMBS		77,062,517			77,062,517
34	Misc Reg Asset	129,705	103,536		129,705	103,536
35						
36						
37						
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41						
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43						
44	**TOTAL :**	381,581,939	236,883,391		42,217,772	576,247,558

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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	991,881		540	360,684	631,197
4	Regulatory Asset-Mt Lease Pymt	2,029,848		540	676,632	1,353,216
5	Colstrip Common Fac.	2,355,642				2,355,642
6	Prepaid Airplane Lease LT	171,693		931	147,165	24,528
7	Misc DD- Airplane Lease	81,591			59,899	21,692
8	Plant Alloc of Clearing Jrl	3,064,335	466,007			3,530,342
9	Misc Posting Suspense	33,635	9,502	var		43,137
10	Renewable Energy-Cert Fees	115,250		557	47,562	67,688
11	Nez Perce Settlement	155,537		557	5,212	150,325
12	Reg Asset ID-Lake CDA	209,081		506	30,975	178,106
13	Credit Union Labor and Exp	38,795			2,321	36,474
14	Misc Work Orders <$50,000	147,095		var	256,317	-109,222
15	Subsidiary Billings	199,887	233,721	var		433,608
16	"Null" Projects Directly to 186	1,353			1,353	
17	Regulatory Assets Consv	1,712,608	165,627			1,878,235
18	Noxon 230 KV Sub Permits	107,860			107,860	
19	Optional Wind Power	-175,295		909	39,761	-215,056
20	Gas Telemetry equip	59,051			52,548	6,503
21	Misc Deffered Debits/Res Acctg	901,446			676,085	225,361
22	Mutual Aid Response PGE		81,208			81,208
23						
24						
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45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	13,312,292				11,803,983

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	04/15/2015	End of 2014/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		5,183,280	8,884,982
3			
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	5,183,280	8,884,982
9	Gas		
10		991,860	1,147,643
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15	991,860	1,147,643
17	Other	64,064,282	113,228,849
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	70,239,422	123,261,474

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	04/15/2015	End of 2014/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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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	04/15/2015	End of 2014/Q4

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
62,243,374	984,400,740					2
				112,042	3,178,632	3
62,243,374	984,400,740			112,042	3,178,632	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	04/15/2015	2014/Q4

FOOTNOTE DATA

Schedule Page: 250 Line No.: 2 Column: a

During 2014, the Company executed a stock repurchase program. Through 12/31/14, the Company repurchased 2,529,615 shares. All repurchased shares under the program were retired and reverted to the status of authorized, but unissued shares. The amounts in account 214 applicable to the retired shares were written off due to the stock repurchase.

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	04/15/2015	End of 2014/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	-9,520,161
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40	TOTAL	-9,520,161

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	04/15/2015	End of 2014/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	-25,079,123
2		
3		
4		
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20		
21		
22	TOTAL	-25,079,123

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

Beginning Balance	$	(19,561,527)
Issuance of Common Stock	$	493,330
Repurchase and Retirement of Common Stock	$	900,721
Tax Benefit-Options Excercised	$	406,364
Excess Tax Benefits on stock compensation	$	357,913
Stock Compensation Accrual	$	(7,675,922)
Ending Balance	**$**	**(25,079,123)**

During 2014, the Company executed a stock repurchase program. Through 12/31/14, the Company repurchased 2,529,615 shares. All repurchased shares under the program were retired and reverted to the status of authorized, but unissued shares. The amounts in account 214 applicable to the retired shares were written off due to the stock repurchase.

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	120,377
5	Discount - FMBS - SERIES A - 7.45% DUE 6/11/2018		50,220
6	FMBS - SERIES A - 7.18% DUE 8/11/2023	7,000,000	54,364
7	ADVANCE ASSOCIATED-AVISTA CAPITAL II (ToPRS)	51,547,000	1,296,086
8	FMBS - 6.37% SERIES C	25,000,000	158,304
9	FMBS - 5.45% SERIES	90,000,000	1,192,681
10	Discount- FMBS - 5.45% SERIES		239,400
11	FMBS - 6.25% SERIES	150,000,000	1,812,935
12	Discount- FMBS - 6.25% SERIES		367,500
13	FMBS - 5.70% SERIES	150,000,000	4,702,304
14	Discount- FMBS - 5.70% SERIES		222,000
15	FMBS - 5.95% SERIES	250,000,000	2,246,419
16	Discount- FMBS - 5.95% SERIES		835,000
17	FMBS - 5.125% SERIES	250,000,000	2,284,788
18	Discount- FMBS - 5.125% SERIES		575,000
19			
20	COLSTRIP 2010A PCRBs DUE 2032	66,700,000	
21	COLSTRIP 2010B PCRBs DUE 2034	17,000,000	
22	FMBS - 3.89% SERIES	52,000,000	385,129
23	FMBS - 5.55% SERIES	35,000,000	258,834
24	4.45% SERIES DUE 12-14-2041	85,000,000	692,833
25	4.23% SERIES DUE 11-29-2047	80,000,000	730,833
26	FMBS- 0.84% SERIES	90,000,000	515,369
27	FMBS- 4.11% SERIES	60,000,000	425,188
28			
29			
30			
31			
32			
33	TOTAL	1,488,247,000	19,270,406

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	04/15/2015	End of 2014/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	414,450	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
						5
08-12-1993	08-11-2023	08-12-1993	08-11-2023	7,000,000	502,600	6
06-03-1997	06-01-2037	06-03-1997	06-01-2037	51,547,000	449,576	7
06-19-1998	06-19-2028	06-19-1998	06-19-2028	25,000,000	1,592,500	8
11-18-2004	12-01-2019	11-18-2004	12-01-2019	90,000,000	4,905,000	9
						10
11-17-2005	12-01-2035	11-17-2005	12-01-2035	150,000,000	9,375,000	11
						12
12-15-2006	07-01-2037	12-15-2006	07-01-2037	150,000,000	8,550,000	13
						14
04-02-2008	06-01-2018	04-02-2008	06-01-2018	250,000,000	14,875,000	15
						16
09-22-2009	04-01-2022	09-22-2009	04-01-2022	250,000,000	12,812,500	17
						18
						19
12-15-2010	10-1-2032	12-15-2010	10-1-2032	66,700,000		20
12-15-2010	3-1-2034	12-15-2010	3-1-2034	17,000,000		21
12-20-2010	12-20-2020	12-20-2010	12-20-2020	52,000,000	2,022,800	22
12-20-2010	12-20-2040	12-20-2010	12-20-2040	35,000,000	1,942,500	23
12-14-2011	12-14-2041	12-14-2011	12-14-2041	85,000,000	3,782,500	24
11-30-2012	11-29-2047	11-30-2012	11-29-2047	80,000,000	3,384,000	25
8-14-2013	8-14-2016	8-13-2013	8-14-2016	90,000,000	756,000	26
12-18-2014	12-1-2044	12-18-14	12-1-2044	60,000,000	89,050	27
						28
						29
						30
						31
						32
				1,488,247,000	67,200,926	33

Schedule Page: 256 Line No.: 7 Column: a

(1) Electric

(2) Natural Gas

Schedule Page: 256 Line No.: 7 Column: i

Upon issuance Avista Capital II issued $1.5 million of Common Trust Securities to the Company. In December 2000, the Company purchased $10.0 million of these Preferred Trust Securities. The interest for the year diclosed in the column (i) reflects the net amount owed to third parties.

Schedule Page: 256 Line No.: 20 Column: a

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.: 20 Column: c

The Company reacquired these bonds in 2010.

Schedule Page: 256 Line No.: 21 Column: a

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.: 21 Column: c

The Company reacquired these bonds in 2010.

Schedule Page: 256 Line No.: 27 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.: 27 Column: c

Expenses may change as more 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	04/15/2015	End of 2014/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)	192,040,688
2		
3		
4	Taxable Income Not Reported on Books	
5		-149,986,684
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		146,365,191
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		7,183,319
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		-252,358,072
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	-69,292,404
28	Show Computation of Tax:	
29	Federal Tax Net Income	
30	State Tax @2%, Less Idaho ITC	-1,858,807
31	Federal Tax Net Income, Less State Tax	-71,151,211
32		
33	Federal Tax @ 35%	-24,902,924
34		
35	Prior Years True ups	-29,198,415
36	Cabinet Gorge Tax Credits	-185,265
37	Total Federal Tax Expense	-54,286,604
38		
39		
40		
41		
42		
43		
44		

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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	162,519		89,714	-2,219,209	-1,392,677
3	Income Tax 2011	2,697,260			661,662	-2,070,474
4	Income Tax 2012	2,014,544				
5	Income Tax 2013	-3,666,967				
6	Income Tax (Current)			-58,137,587	-23,335,818	470,244
7	Retained Earnings					
8	Prior Retained Earnings	-1,392,677				1,392,677
9	Prior Retained Earnings	-2,070,474				2,070,474
10	Prior Retained Earnings	-2,124,050				
11	Prior Retained Earnings	-483,257				
12	Current Retained Earnings					-470,244
13	Total Federal	-4,863,102		-58,047,873	-24,893,365	
14						
15	STATE OF WASHINGTON:					
16	Property Tax (2012)	405		-405		
17	Property Tax (2013)	12,098,968		-96,763	12,002,205	
18	Property Tax (2014)			14,264,301		
19	Excise Tax (2010)	-22,495				
20	Excise Tax (2013)	2,862,373		-19,365	2,843,932	924
21	Excise Tax (2014)			25,985,628	23,217,121	
22	Natural Gas Use Tax	9,107		5,250	4,600	-8,348
23	Municipal Occupation Tax	3,052,429		23,805,376	23,904,238	
24	Sales & Use Tax (2012)	-10,661			-10,661	
25	Sales & Use Tax (2013)	103,048			103,365	318
26	Sales & Use Tax (2014)			907,515	834,948	-317
27	Total Washington	18,093,174		64,851,537	62,899,748	-7,423
28						
29	STATE OF IDAHO:					
30	Income Tax (2013)	-63,461		104,681		
31	Income Tax (2014)			294,500	181,220	
32	Property Tax (2012)	352,996		-352,996		
33	Property Tax (2013)	3,319,617		-13,235	3,307,101	
34	Property Tax (2014)			6,783,896	3,386,321	
35	Sales & Use Tax (2013)	4,043			4,043	
36	Sales & Use Tax (2014)			169,667	164,050	
37	KWH Tax (2012)	1				
38	KWH Tax (2013)	19,184		-134	19,050	
39	KWH Tax (2014)			438,004	410,861	
40	Franchise Tax (2013)	1,573,957			1,577,085	
41	TOTAL	22,103,801		34,351,694	67,180,792	-3

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	04/15/2015	End of 2014/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
1,078,764					89,714	2
-34,876						3
2,014,544						4
-3,666,967						5
-34,331,525		-5,279,512			-52,858,075	6
						7
						8
						9
-2,124,050						10
-483,257						11
-470,244						12
-38,017,611		-5,279,512			-52,768,361	13
						14
						15
		-405				16
		-148,364			51,601	17
14,264,301		11,286,939			2,977,362	18
-22,495						19
		-21,453			2,088	20
2,768,507		19,708,537			6,277,091	21
1,409		5,250				22
2,953,568		17,690,449			6,114,927	23
						24
1						25
72,250					907,515	26
20,037,541		48,520,953			16,330,584	27
						28
						29
41,220		83,745			20,936	30
113,280		377,935			-83,435	31
		-350,376			-2,620	32
-719		-13,235				33
3,397,575		5,483,117			1,300,779	34
						35
5,617					169,667	36
1						37
		-134				38
27,143		438,652			-648	39
-3,128						40
-10,725,297		63,584,050			-29,232,356	41

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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	Franchise Tax (2014)			4,676,179	3,025,490	
2	Total Idaho	5,206,337		12,100,562	12,075,221	
3						
4	STATE OF MONTANA:					
5	Income Tax (2011 & Prior)				-22,865	
6	Income Tax (2012)	-68,011			-68,011	
7	Income Tax (2013)	183,678		-469,605	-408,543	-122,616
8	Income Tax (2014)			-348,731	75,000	
9	Property Tax (2012)	431		-431		
10	Property Tax (2013)	4,071,297			4,071,297	
11	Property Tax (2014)			8,465,757	4,239,318	
12	Colstrip Generation Tax			1,538	1,538	
13	KWH Tax (2013)	166,901			166,901	
14	KWH Tax (2014)			1,175,493	912,013	
15	Consumer Council Tax	11		48	50	
16	Public Commission Tax	43		165	190	1
17	Total Montana	4,354,350		8,824,234	8,966,888	-122,615
18						
19	STATE OF OREGON:					
20	Income Tax (2012)	-25,001			-125,000	
21	Income Tax (2013)	786,066		-886,067	-100,000	1
22	Income Tax (2014)			-555,185	100,000	
23	Property Tax (2013)	-2,086,107				-1
24	Property Tax (2014)			4,829,077	4,915,625	
25	BETC Credit (2010 and Prior)	-17,483				
26	BETC Credit (2011)	-29,962				
27	BETC Credit (2012)	-57,789				
28	Glendate Regulatory Cr. 2009	-34,911				
29	Franchise Tax (2010)	513		-513		
30	Franchise Tax (2012)	24,531			24,258	-273
31	Franchise Tax (2013)	889,814			889,921	107
32	Franchise Tax (2014)			3,358,313	2,582,151	166
33	Total Oregon	-550,329		6,745,625	8,286,955	
34						
35	STATE OF CALIFORNIA:					
36	Income Tax (2011)	-800				
37	Income Tax (2013)	-1,600		1,600		
38	Income Tax (2014)				1,600	
39	Total California	-2,400		1,600	1,600	
40						
41	TOTAL	22,103,801		34,351,694	67,180,792	-3

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	04/15/2015	End of 2014/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)	
1,650,689		3,368,298			1,307,881	1
5,231,678		9,388,002			2,712,560	2
						3
						4
22,865						5
						6
		-469,605				7
-423,731		-348,731				8
		-431				9
						10
4,226,439		8,465,757				11
		1,538				12
						13
263,479		1,175,493				14
9		48				15
19		165				16
4,089,080		8,824,234				17
						18
						19
99,999						20
		-221,517			-664,550	21
-655,185		-138,799			-416,386	22
-2,086,108						23
-86,548		2,490,689			2,338,388	24
-17,483						25
-29,962						26
-57,789						27
-34,911						28
					-513	29
						30
						31
776,328					3,358,313	32
-2,091,659		2,130,373			4,615,252	33
						34
						35
-800						36
					1,600	37
-1,600						38
-2,400					1,600	39
						40
-10,725,297		63,584,050			-29,232,356	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	04/15/2015	End of 2014/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)	BALANCE AT BEGINNING OF YEAR Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	MISCELLANEOUS STATES:					
2	Income Tax (2012)					
3	Income Tax (2013)	-122,613				122,614
4	Income Tax (2014)			28,632		
5	Total Misc States	-122,613		28,632		122,614
6						
7	COUNTY & MUNICIPAL					
8	Vehicle Excise Tax					
9	WA Renewable Energy	-561		-228,689	-228,689	
10	Misc.	-11,055		76,066	72,434	7,421
11	Total County	-11,616		-152,623	-156,255	7,421
12						
13						
14						
15						
16						
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40						
41	TOTAL	22,103,801		34,351,694	67,180,792	-3

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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
						2
1						3
28,632					28,632	4
28,633					28,632	5
						6
						7
						8
-561					-228,689	9
2					76,066	10
-559					-152,623	11
						12
						13
						14
						15
						16
						17
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						36
						37
						38
						39
						40
-10,725,297		63,584,050			-29,232,356	41

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		12,234,367	411	-195,528			
7							
8	TOTAL	12,234,367		-195,528			
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Gas Property (100%	46,176			411	12,672	
11		106,488			411	21,324	
12	TOTAL PROPERTY	152,664				33,996	
13							
14							
15							
16							
17							
18							
19							
20							
21							
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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	04/15/2015	End of 2014/Q4

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
12,038,839			6
			7
12,038,839			8
			9
33,504			10
85,164			11
118,668			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
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			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	04/15/2015	End of 2014/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 (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Defer Gas Exchange (253028)	1,500,000		375,010		1,124,990
2	Rathdrum Refund (253120)	205,754		33,822		171,932
3	NE Tank Spill (253130)	16,782			9,746	26,528
4	Kettle Falls Diesel Leak (254135)				664,699	664,699
5	Bills Pole Rentals (253140)	296,339			15,301	311,640
6	CR-CS2 GE LTSA (253150)	2,003,140		838,472		1,164,668
7	CR-Credit Resource Actg	901,446		676,085		225,361
8	DOC EECE Grant (253155)	271,380		94,098		177,282
9	Defer Comp Retired Execs (253900)	36,255		25,926		10,329
10	Defer Comp Active Execs (253910)	9,170,452		493,566		8,676,886
11	Executive Incent Plan (253920)	140,000				140,000
12	Unbilled Revenue (253990)	1,048,274		374,016		674,258
13	WA Energy Recovery Mechanism	8,024,194		8,024,194	4,224,011	4,224,011
14	Misc Deferred Credits	138,369		138,369	3,677,156	3,677,156
15	REC Deferral	1,606,948		1,606,948		
16						
17						
18						
19						
20						
21						
22						
23						
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45						
46						
47	TOTAL	25,359,333		12,680,506	8,590,913	21,269,740

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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) 04/15/2015	Year/Period of Report End of 2014/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	Balance at Beginning of Year	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1	Amounts Credited to Account 411.1
	(a)	(b)	(c)	(d)
1	Account 282			
2	Electric	298,124,105	91,710,027	
3	Gas	104,243,017	37,166,301	
4	Other	44,733,113	6,744,789	
5	TOTAL (Enter Total of lines 2 thru 4)	447,100,235	135,621,117	
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	447,100,235	135,621,117	
10	Classification of TOTAL			
11	Federal Income Tax	436,033,912	131,984,301	
12	State Income Tax	11,066,323	3,636,816	
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) 04/15/2015	Year/Period of Report End of 2014/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
						389,834,132	2
						141,409,318	3
						51,477,902	4
						582,721,352	5
							6
							7
							8
						582,721,352	9
							10
						568,018,213	11
						14,703,139	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	04/15/2015	End of 2014/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	19,241,501	-2,526,001	
4				
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	19,241,501	-2,526,001	
10	Gas			
11	Gas	-3,856,614	3,085,379	
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	-3,856,614	3,085,379	
18	Other	146,459,547	-3,061,139	
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	161,844,434	-2,501,761	
20	Classification of TOTAL			
21	Federal Income Tax	161,844,434	-2,501,761	
22	State Income Tax			
23	Local Income Tax			

NOTES

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					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
1,128,945					-500,852	17,343,593	3
							4
							5
							6
							7
							8
1,128,945					-500,852	17,343,593	9
							10
					62,407	-708,828	11
							12
							13
							14
							15
							16
					62,407	-708,828	17
	5,739,597				70,560,211	208,219,022	18
1,128,945	5,739,597				70,121,766	224,853,787	19
							20
1,128,945	5,739,597				70,121,766	224,853,787	21
							22
							23

NOTES (Continued)

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Idaho Investment Tax Credit (254005)	5,409,558			5,052,481	10,462,039
2	Oregon BETC Credit (254010)	500,000			331,138	831,138
3	Noxon, ITC (254025)	3,293,863	190	52,632		3,241,231
4	Settled Int Rate Swaps (254090)	12,965,590			3,457,962	16,423,552
5	Unsettled Int Rate Swaps (254100)	33,543,258	176	33,082,942		460,316
6	Oregon Commercial Fee (254120)			1,942	1,942	
7	FAS 109 Invest Credit (254180)	82,200	190	18,300		63,900
8	Nez Perce (254220)	660,356	557	22,008		638,348
9	Idaho Earnings Test (254229)				4,275,418	4,275,418
10	Oregon Senate Bill (254250)		407	73,357	73,357	
11	Decoupling Rebate (254328)	2,279	407	2,279		
12	BPA Parallel Cap (254331)	5,397,106	407	4,588,970		808,136
13	BPA RES EXCH (254345)		407		1,659,457	1,659,457
14	Unrealized Currency Exchange (254399)		143	28,237	28,237	
15	Idaho PCA	9,879,394		9,879,394	9,962,091	9,962,091
16	Roseburg/Medford	8,726		8,726	8,729	8,729
17						
18						
19						
20						
21						
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27						
28						
29						
30						
31						
32						
33						
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38						
39						
40						
41	TOTAL	71,742,330		47,758,787	24,850,812	48,834,355

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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	04/15/2015	End of 2014/Q4

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	338,697,524	331,866,712
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	300,108,664	289,604,042
5	Large (or Ind.) (See Instr. 4)	110,774,727	113,631,878
6	(444) Public Street and Highway Lighting	7,549,449	7,266,653
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	1,163,952	1,103,974
10	TOTAL Sales to Ultimate Consumers	758,294,316	743,473,259
11	(447) Sales for Resale	150,887,383	143,390,565
12	TOTAL Sales of Electricity	909,181,699	886,863,824
13	(Less) (449.1) Provision for Rate Refunds	7,503,194	2,047,837
14	TOTAL Revenues Net of Prov. for Refunds	901,678,505	884,815,987
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	527,893	590,953
18	(453) Sales of Water and Water Power	475,000	432,332
19	(454) Rent from Electric Property	3,037,405	3,023,492
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	94,639,088	135,207,886
22	(456.1) Revenues from Transmission of Electricity of Others	14,745,982	25,386,252
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	113,425,368	164,640,915
27	TOTAL Electric Operating Revenues	1,015,103,873	1,049,456,902

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	04/15/2015	End of 2014/Q4

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
3,693,787	3,745,255	324,188	321,098	2
				3
3,189,422	3,146,819	40,988	40,202	4
1,868,012	1,979,324	1,385	1,386	5
25,116	25,818	531	527	6
				7
				8
12,585	12,193	103	99	9
8,788,922	8,909,409	367,195	363,312	10
4,050,611	4,409,585			11
12,839,533	13,318,994	367,195	363,312	12
				13
12,839,533	13,318,994	367,195	363,312	14

Line 12, column (b) includes $ 1,516,880 of unbilled revenues.

Line 12, column (d) includes 12,644 MWH relating to unbilled revenues

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	04/15/2015	End of 2014/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	RESIDENTIAL SALES (440)	3,547,030	311,952,512	308,537	11,496	0.0879
2	1 Residential Service					
3	2 Residential Service					
4	3 Residential Service					
5	12 Res. & Farm Gen. Service	82,458	10,876,479	13,838	5,959	0.1319
6	15 MOPS II Residential					
7	22 Res. & Farm Lg. Gen. Service	46,603	3,924,929	73	638,397	0.0842
8	30 Pumping-Special	1	246	1	1,000	0.2460
9	32 Res. & Farm Pumping Service	9,271	1,043,594	1,739	5,331	0.1126
10	48 Res. & Farm Area Lighting	4,276	1,059,577			0.2478
11	49 Area Lighting-High-Press.	233	74,068			0.3179
12	56 Centralia Refund					
13	95 Wind Power		155,576			
14	72 Residential Service					
15	73 Residential Service					
16	74 Residential Service					
17	76 Residential Service					
18	77 Residential Service					
19	58A Tax Adjustment		-46,839			
20	58 Tax Adjustment		9,289,661			
21	SubTotal	3,689,872	338,329,803	324,188	11,382	0.0917
22	Residential-Unbilled	3,915	367,721			0.0939
23	Total Residential Sales	3,693,787	338,697,524	324,188	11,394	0.0917
24						
25	COMMERCIAL SALES (442)					
26	2 General Service					
27	3 General Service					
28	11 General Service	861,688	95,281,683	36,925	23,336	0.1106
29	12 Res. & Farm Gen. Service					
30	16 MOPS II Commercial					
31	19 Contract-General Service					
32	21 Large General Service	1,860,236	161,220,316	2,917	637,722	0.0867
33	25 Extra Lg. Gen. Service	352,699	21,686,564	13	27,130,692	0.0615
34	28 Contract-Extra Large Serv					
35	31 Pumping Service	99,959	8,311,284	1,133	88,225	0.0831
36	47 Area Lighting-Sod. Vap	6,082	1,363,883			0.2242
37	49 Area Lighting-High-Press.	2,547	611,624			0.2401
38	56 Centralia Refune					
39	95 Wind Power		77,377			
40	74 Large General Service					
41	TOTAL Billed	12,826,889	907,664,819	367,195	34,932	0.0708
42	Total Unbilled Rev.(See Instr. 6)	12,644	1,516,880	0	0	0.1200
43	TOTAL	12,839,533	909,181,699	367,195	34,967	0.0708

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	04/15/2015	End of 2014/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		-40,158			
5	58 Tax Adjustment		10,738,629			
6	SubTotal	3,183,211	299,251,202	40,988	77,662	0.0940
7	Commercial-Unbilled	6,211	857,462			0.1381
8	Total Commercial	3,189,422	300,108,664	40,988	77,814	0.0941
9						
10	INDUSTRIAL SALES (442)					
11	2 General Service					
12	3 General Service					
13	8 Lg Gen Time of Use					
14	11 General Service	10,899	1,228,699	260	41,919	0.1127
15	12 Res. & Farm Gen. Service					
16	21 Large General Service	212,170	17,730,632	157	1,351,401	0.0836
17	25 Extra Lg. Gen. Service	1,551,109	83,220,199	18	86,172,722	0.0537
18	28 Contract - Extra Large Service					
19	29 Contract Lg. Gen. Service					
20	30 Pumping Service - Special	24,819	1,720,526	31	800,613	0.0693
21	31 Pumping Service	61,628	5,273,607	775	79,520	0.0856
22	32 Pumping Svc Res & Firm	4,578	394,100	144	31,792	0.0861
23	47 Area Lighting-Sod. Vap.	227	49,607			0.2185
24	49 Area Lighting - High-Press	64	14,597			0.2281
25	95 Wind Power		1,798			
26	48 Area Lighting-Sod. Vap.					
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		-1,166			
33	58 Tax Adjustment		850,431			
34	SubTotal	1,865,494	110,483,030	1,385	1,346,927	0.0592
35	Industrial-Unbilled	2,518	291,697			0.1158
36	Total Industrial	1,868,012	110,774,727	1,385	1,348,745	0.0593
37						
38	STREET AND HWY LIGHTING (444)					
39	6 Mercury Vapor St. Ltg.					
40	7 HP Sodium Vap. St. Ltg					
41	TOTAL Billed	12,826,889	907,664,819	367,195	34,932	0.0708
42	Total Unbilled Rev.(See Instr. 6)	12,644	1,516,880	0	0	0.1200
43	TOTAL	12,839,533	909,181,699	367,195	34,967	0.0708

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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	35	4,448	3	11,667	0.1271
2	41 Co-Owned St. Lt. Service	214	42,747	16	13,375	0.1998
3	42 Co-Owned St. Lt. Service	20,502	6,811,479	399	51,383	0.3322
4	High-Press. Sod. Vap.					
5	43 Cust-Owned St. Lt. Energy	2	263	1	2,000	0.1315
6	and Maint. Service					
7	44 Cust-Owned St. Lt. Energy	631	97,530	30	21,033	0.1546
8	and Maint. Svce - High-Pres					
9	Sodium Vapor					
10	45 Cust. Owned St. Lt. Energy Svc	1,415	99,755	16	88,438	0.0705
11	46 Cust. Owned St. Lt. Energy Svc	2,317	221,546	66	35,106	0.0956
12	58A Tax Adjustment		-780			
13	58 Tax Adjustment		272,461			
14	SubTotal	25,116	7,549,449	531	47,299	0.3006
15	Street & Hwy Lighting-Unbilled					
16	Total Street & Hwy Lighting	25,116	7,549,449	531	47,299	0.3006
17						
18	OTHER SALES TO PUBLIC					
19	(445)					
20	None					
21						
22	INTERDEPARTMENTAL SALES	12,585	1,163,952	103	122,184	0.0925
23	58 Tax Adjustment					
24	Total Interdepartmental	12,585	1,163,952	103	122,184	0.0925
25						
26	SALES FOR RESALE (447)	4,050,611	150,887,383			0.0373
27	61 Sales to Other Utilities (NDA)					
28						
29						
30	Total Sales for Resale	4,050,611	150,887,383			0.0373
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	12,826,889	907,664,819	367,195	34,932	0.0708
42	Total Unbilled Rev.(See Instr. 6)	12,644	1,516,880	0	0	0.1200
43	TOTAL	12,839,533	909,181,699	367,195	34,967	0.0708

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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	04/15/2015	End of 2014/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	Bonneville Power Administration	LF	Tariff 8			
4	Bonneville Power Administration	LF	ACS-06			
5	Bonneville Power Administration	SF	Tariff 9			
6	Bonneville Power Administration	LF	Tariff 12			
7	British Columbia Hydro and Power Author	LF	Tariff 12			
8	Brookfield Energy Marketing LP	SF	Tariff 9			
9	Burbank, City of	SF	Tariff 9			
10	Calpine Energy Services LP	SF	Tariff 9			
11	Cargill Power Markets, LLC	SF	Tariff 9			
12	Chelan County PUD No. 1	SF	Tariff 9			
13	Chelan County PUD No. 1	LF	Tariff 12			
14	Clark County PUD No. 1	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	04/15/2015	End of 2014/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,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.
			499,832	499,832	1
58,366		2,200,119		2,200,119	2
21,052		844,597		844,597	3
4,445		90,153		90,153	4
74,058		2,683,484		2,683,484	5
35		1,091		1,091	6
38		1,397		1,397	7
1,600		68,500		68,500	8
1,600		38,000		38,000	9
45,550		1,417,269		1,417,269	10
188,645		5,680,778		5,680,778	11
112,800		3,859,558		3,859,558	12
2		66		66	13
15,774		614,864		614,864	14
0	0	0	0	0	
4,050,611	7,414,268	118,296,763	25,176,352	150,887,383	
4,050,611	**7,414,268**	**118,296,763**	**25,176,352**	**150,887,383**	

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	04/15/2015	End of 2014/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	Clatskanie Peoples PUD	SF	Tariff 9			
2	ConocoPhillips	SF	Tariff 9			
3	DB Energy Trading, LLC	SF	Tariff 9			
4	Douglas County PUD No. 1	SF	Tariff 9			
5	Douglas County PUD No. 1	LF	Tariff 12			
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	SF	Tariff 9			
11	Gridforce Energy Management, LLC	LF	Tariff 12			
12	Iberdrola Renewables, LLC	SF	Tariff 9			
13	Iberdrola Renewables, LLC	SF	Tariff 9			
14	Idaho Power Company	SF	Tariff 9			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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 invoiving 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.
1,233		87,770		87,770	1
400		15,400		15,400	2
		-423		-423	3
16,045		600,716		600,716	4
4		96		96	5
163,512		3,792,479		3,792,479	6
12,301		369,215		369,215	7
19,036		721,383		721,383	8
12,393		467,048		467,048	9
	7,180			7,180	10
75		2,386		2,386	11
384,784		13,008,801		13,008,801	12
	745,110			745,110	13
14,850		247,441		247,441	14
0	0	0	0	0	
4,050,611	7,414,268	118,296,763	25,176,352	150,887,383	
4,050,611	**7,414,268**	**118,296,763**	**25,176,352**	**150,887,383**	

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	04/15/2015	End of 2014/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)	Average Monthly CP Demand (f)
1	Idaho Power Company	LF	Tariff 12			
2	Idaho Power Balancing	SF	Tariff 9			
3	J. Aron & Company	SF	Tariff 9			
4	JP Morgan Ventures Energy	SF	Tariff 9			
5	Kootenai Electric Cooperative	LF	Tariff 8			
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	04/15/2015	End of 2014/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,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.
11		258		258	1
127,401		3,771,859		3,771,859	2
24,800		1,467,808		1,467,808	3
16,512		555,926		555,926	4
695		21,174		21,174	5
112,678		4,038,445		4,038,445	6
			579,343	579,343	7
7,091		338,716		338,716	8
188,835		6,863,834		6,863,834	9
	275,940			275,940	10
	1,975,375			1,975,375	11
	289,245			289,245	12
5,897		171,318		171,318	13
15		442		442	14
0	0	0	0	0	
4,050,611	7,414,268	118,296,763	25,176,352	150,887,383	
4,050,611	**7,414,268**	**118,296,763**	**25,176,352**	**150,887,383**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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	NaturEner Power Watch, LLC	SF	Tariff 9			
2	NaturEner Power Watch, LLC	SF	Tariff 9			
3	Nevada Power Company	SF	Tariff 9			
4	NextEra Energy Power Market	SF	Tariff 9			
5	Noble America Gas & Power	SF	Tariff 9			
6	NorthWestern Energy LLC	SF	Tariff 9			
7	NorthWestern Energy LLC	LF	Tariff 12			
8	NorthWestern Energy LLC	LF	Tariff 9			
9	NorthWestern Energy LLC	SF	Tariff 10			
10	Okanogan County PUD	SF	Tariff 9			
11	PacifiCorp	SF	Tariff 9			
12	PacifiCorp	LF	Tariff 12			
13	PacifiCorp	LF	Tariff 9			
14	Peaker LLC	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	04/15/2015	End of 2014/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,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.
	179,880			179,880	1
	275,940			275,940	2
1,473		38,529		38,529	3
49,934		2,383,154		2,383,154	4
963		3,141		3,141	5
119,785		4,616,291		4,616,291	6
97		3,219		3,219	7
7,675		240,633		240,633	8
	1,344,695			1,344,695	9
14,685		627,741		627,741	10
101,245		4,134,979		4,134,979	11
269		10,088		10,088	12
4,886		153,130		153,130	13
	1,748,825			1,748,825	14
0	0	0	0	0	
4,050,611	7,414,268	118,296,763	25,176,352	150,887,383	
4,050,611	**7,414,268**	**118,296,763**	**25,176,352**	**150,887,383**	

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	04/15/2015	End of 2014/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	Pend Oreille Public Utility District	IF	Tariff 9			
2	Pend Oreille Public Utility District	IF	Tariff 9			
3	Pend Oreille Public Utility District	SF	Tariff 9			
4	Pend Oreille Public Utility District	IF	290 (PNCA)			
5	Portland General Electric Company	SF	Tariff 9			
6	Portland General Electric Company	LF	Tariff 12			
7	Powerex	SF	Tariff 9			
8	Powerex	SF	Tariff 9			
9	PPL EnergyPlus, LLC	SF	Tariff 9			
10	PPL EnergyPlus, LLC	SF	Tariff 9			
11	PPL Montana	LF	Tariff 9			
12	Puget Sound Energy	LF	Tariff 9			
13	Puget Sound Energy	SF	Tariff 9			
14	Puget Sound Energy	LF	Tariff 12			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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,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.
	450,958			450,958	1
14,250		433,861		433,861	2
64,629		1,564,324		1,564,324	3
-14	3,278			3,278	4
112,184		3,231,568		3,231,568	5
31		1,515		1,515	6
258,716		7,019,015		7,019,015	7
	250			250	8
	18,740			18,740	9
45,798		1,699,428		1,699,428	10
17,442		546,893		546,893	11
22,328		700,023		700,023	12
321,237		12,638,186		12,638,186	13
28		761		761	14
0	0	0	0	0	
4,050,611	7,414,268	118,296,763	25,176,352	150,887,383	
4,050,611	**7,414,268**	**118,296,763**	**25,176,352**	**150,887,383**	

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	04/15/2015	End of 2014/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	Rainbow Energy Marketing	SF	Tariff 9			
2	Sacramento Municipal Utility District	SF	Tariff 9			
3	Sacramento Municipal Utility District	LF	Tariff 9			
4	Seattle City Light	SF	Tariff 9			
5	Seattle City Light	LF	Tariff 12			
6	SG Americas Securities, LLC	SF	ISDA			
7	Shell Energy N.A.	SF	Tariff 9			
8	Shell Energy N.A.	SF	ISDA			
9	Sierra Pacific Power Company	SF	Tariff 9			
10	Sierra Pacific Power Company	LF	Tariff 12			
11	Snohomish County PUD	SF	Tariff 9			
12	Sovereign Power	LF	Tariff 9			
13	Sovereign Power	LF	Tariff 9			
14	Tacoma Power	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	04/15/2015	End of 2014/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,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.
26,354		958,567		958,567	1
125,781		4,237,309		4,237,309	2
435,647		20,000,292		20,000,292	3
12,566		408,129		408,129	4
10		317		317	5
			1,967,714	1,967,714	6
466,621		13,761,995		13,761,995	7
			-250,356	-250,356	8
335		2,845		2,845	9
38		1,390		1,390	10
11,836		510,132		510,132	11
	97,552			97,552	12
13,274		402,801		402,801	13
13,585		330,241		330,241	14
0	0	0	0	0	
4,050,611	7,414,268	118,296,763	25,176,352	150,887,383	
4,050,611	**7,414,268**	**118,296,763**	**25,176,352**	**150,887,383**	

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	04/15/2015	End of 2014/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	Tacoma Power	LF	Tariff 12			
2	Tacoma Power	SF	Tariff 9			
3	Tenaska Power Services Co.	SF	Tariff 9			
4	The Energy Authority	SF	Tariff 9			
5	TransAlta Energy Marketing	SF	Tariff 9			
6	Tri-State Generation & Transmission As	SF	Tariff 9			
7	Turlock Irrigation District	SF	Tariff 9			
8	Turlock Irrigation District	LF	Tariff 12			
9	IntraCompany Wheeling	LF				
10	IntraCompany Generation	LF				
11						
12						
13						
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	04/15/2015	End of 2014/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,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.
7		211		211	1
	1,300			1,300	2
4,126		100,678		100,678	3
29,546		1,128,820		1,128,820	4
119,710		3,794,018		3,794,018	5
200		600		600	6
800		22,800		22,800	7
1		39		39	8
		-21,452,868	21,452,868		9
			926,951	926,951	10
					11
					12
					13
					14
0	0	0	0	0	
4,050,611	7,414,268	118,296,763	25,176,352	150,887,383	
4,050,611	**7,414,268**	**118,296,763**	**25,176,352**	**150,887,383**	

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

Schedule Page: 310 Line No.: 3 Column: b
BPA Contract Terminates September 30, 2028.

Schedule Page: 310 Line No.: 4 Column: b
BPA Contract Terminates January 1, 2036.

Schedule Page: 310 Line No.: 6 Column: b
NWPP Reserve Sharing Sales

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

Schedule Page: 310 Line No.: 13 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.1 Line No.: 5 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.1 Line No.: 11 Column: b
NWPP Reserve Sharing Sales

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

Schedule Page: 310.2 Line No.: 1 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.2 Line No.: 5 Column: b
Kootenai Contract Terminates March 31,2019

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.: 7 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.3 Line No.: 8 Column: b
NorthWestern Energy LLC sale expires October 31, 2018.

Schedule Page: 310.3 Line No.: 12 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.3 Line No.: 13 Column: b
PacifiCorp sale terminates October 31, 2018.

Schedule Page: 310.3 Line No.: 14 Column: b
Peaker, LLC capacity contract terminates December 31, 2016.

Schedule Page: 310.4 Line No.: 1 Column: b
Contract expires 9/30/2017.

Schedule Page: 310.4 Line No.: 2 Column: b
Contract expires 9/30/2017.

Schedule Page: 310.4 Line No.: 4 Column: b
Contract expires 9/30/2017.

Schedule Page: 310.4 Line No.: 6 Column: b
NWPP Reserve Sharing Sales

Schedule Page: 310.4 Line No.: 11 Column: b
PPL sale terminates October 31, 2018.

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

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	04/15/2015	2014/Q4

FOOTNOTE DATA

Schedule Page: 310.4 Line No.: 14 Column: b

NWPP Reserve Sharing Sales

Schedule Page: 310.5 Line No.: 3 Column: b

Contract expires 2014.

Schedule Page: 310.5 Line No.: 5 Column: b

NWPP Reserve Sharing Sales

Schedule Page: 310.5 Line No.: 6 Column: b

SWAP - Formerly Newedge USA, LLC

Schedule Page: 310.5 Line No.: 8 Column: b

SWAP

Schedule Page: 310.5 Line No.: 10 Column: b

NWPP Reserve Sharing Sales

Schedule Page: 310.5 Line No.: 12 Column: b

Sovereign Power contract terminates 9-30-2019

Schedule Page: 310.5 Line No.: 13 Column: b

Sovereign Power Contract terminates 9-30-2019

Schedule Page: 310.6 Line No.: 1 Column: b

NWPP Reserve Sharing Sales

Schedule Page: 310.6 Line No.: 8 Column: b

NWPP Reserve Sharing Sales

Schedule Page: 310.6 Line No.: 9 Column: a

Intracompany Wheeling

Schedule Page: 310.6 Line No.: 9 Column: b

IntraCompany Wheeling terminates 09/30/2023.

Schedule Page: 310.6 Line No.: 10 Column: a

IntraCompany Generation - Sale of Ancillary Services

Schedule Page: 310.6 Line No.: 10 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	04/15/2015	End of 2014/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	208,443	281,941
5	(501) Fuel	29,005,009	24,772,509
6	(502) Steam Expenses	3,835,814	4,198,197
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	984,464	1,017,827
10	(506) Miscellaneous Steam Power Expenses	2,295,553	2,880,540
11	(507) Rents	40,851	33,093
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	36,370,134	33,184,107
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	593,388	457,703
16	(511) Maintenance of Structures	795,357	680,769
17	(512) Maintenance of Boiler Plant	5,541,250	6,100,955
18	(513) Maintenance of Electric Plant	2,010,267	1,172,747
19	(514) Maintenance of Miscellaneous Steam Plant	2,739,562	799,354
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	11,679,824	9,211,528
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	48,049,958	42,395,635
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	2,273,416	1,908,948
45	(536) Water for Power	1,304,313	1,303,492
46	(537) Hydraulic Expenses	7,158,884	7,200,656
47	(538) Electric Expenses	6,065,458	6,644,506
48	(539) Miscellaneous Hydraulic Power Generation Expenses	665,656	716,024
49	(540) Rents	6,931,274	6,851,497
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	24,399,001	24,625,123
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	857,660	549,213
54	(542) Maintenance of Structures	891,640	979,941
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,291,737	1,781,796
56	(544) Maintenance of Electric Plant	2,817,753	4,157,781
57	(545) Maintenance of Miscellaneous Hydraulic Plant	683,027	578,169
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	6,541,817	8,046,900
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	30,940,818	32,672,023

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	04/15/2015	End of 2014/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	1,416,384	1,394,573
63	(547) Fuel	89,150,873	110,462,332
64	(548) Generation Expenses	1,841,494	2,146,858
65	(549) Miscellaneous Other Power Generation Expenses	625,162	462,952
66	(550) Rents	-37,276	-27,127
67	TOTAL Operation (Enter Total of lines 62 thru 66)	92,996,637	114,439,588
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	1,113,316	1,080,319
70	(552) Maintenance of Structures	76,791	50,978
71	(553) Maintenance of Generating and Electric Plant	2,358,167	1,994,695
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	579,369	182,724
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	4,127,643	3,308,716
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	97,124,280	117,748,304
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	197,691,167	205,763,918
77	(556) System Control and Load Dispatching	978,453	965,965
78	(557) Other Expenses	87,372,432	121,667,121
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	286,042,052	328,397,004
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	462,157,108	521,212,966
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,248,616	2,476,590
84			
85	(561.1) Load Dispatch-Reliability	45,521	24,584
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,334,633	1,296,586
87	(561.3) Load Dispatch-Transmission Service and Scheduling	1,074,917	1,107,366
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	496,548	457,928
94	(563) Overhead Lines Expenses	537,485	525,234
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	18,896,022	17,926,901
97	(566) Miscellaneous Transmission Expenses	1,943,266	1,969,445
98	(567) Rents	154,350	101,823
99	TOTAL Operation (Enter Total of lines 83 thru 98)	26,731,358	25,886,457
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	802,377	1,095,334
102	(569) Maintenance of Structures	379,954	384,459
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	1,421,588	1,353,879
108	(571) Maintenance of Overhead Lines	1,733,944	1,473,050
109	(572) Maintenance of Underground Lines	-6,721	21,166
110	(573) Maintenance of Miscellaneous Transmission Plant	101,431	49,081
111	TOTAL Maintenance (Total of lines 101 thru 110)	4,432,573	4,376,969
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	31,163,931	30,263,426

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	04/15/2015	End of 2014/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	3,207,049	2,459,976
135	(581) Load Dispatching		
136	(582) Station Expenses	598,094	658,164
137	(583) Overhead Line Expenses	2,304,774	2,570,589
138	(584) Underground Line Expenses	1,358,460	1,208,803
139	(585) Street Lighting and Signal System Expenses	62,128	96,492
140	(586) Meter Expenses	1,883,128	2,535,810
141	(587) Customer Installations Expenses	642,752	723,178
142	(588) Miscellaneous Expenses	7,507,882	6,388,373
143	(589) Rents	262,726	165,290
144	TOTAL Operation (Enter Total of lines 134 thru 143)	17,826,993	16,806,675
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	1,779,538	1,693,053
147	(591) Maintenance of Structures	296,322	338,632
148	(592) Maintenance of Station Equipment	857,682	1,098,232
149	(593) Maintenance of Overhead Lines	8,750,043	8,701,264
150	(594) Maintenance of Underground Lines	999,281	1,093,965
151	(595) Maintenance of Line Transformers	846,026	863,170
152	(596) Maintenance of Street Lighting and Signal Systems	714,295	809,998
153	(597) Maintenance of Meters	14,354	33,257
154	(598) Maintenance of Miscellaneous Distribution Plant	568,833	433,209
155	TOTAL Maintenance (Total of lines 146 thru 154)	14,826,374	15,064,780
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	32,653,367	31,871,455
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	323,796	353,964
160	(902) Meter Reading Expenses	2,844,990	3,209,973
161	(903) Customer Records and Collection Expenses	8,422,061	8,851,168
162	(904) Uncollectible Accounts	2,751,684	2,534,687
163	(905) Miscellaneous Customer Accounts Expenses	197,184	237,659
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	14,539,715	15,187,451

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	25,895,701	20,642,475
169	(909) Informational and Instructional Expenses	869,523	1,040,149
170	(910) Miscellaneous Customer Service and Informational Expenses	178,084	201,012
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	26,943,308	21,883,636
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses		7,402
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)		7,402
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	24,851,565	24,995,618
182	(921) Office Supplies and Expenses	4,477,202	4,124,034
183	(Less) (922) Administrative Expenses Transferred-Credit	135,133	102,053
184	(923) Outside Services Employed	11,883,975	10,535,127
185	(924) Property Insurance	1,367,671	1,449,064
186	(925) Injuries and Damages	3,666,296	3,100,513
187	(926) Employee Pensions and Benefits	2,096,877	1,214,925
188	(927) Franchise Requirements	3,775	5,747
189	(928) Regulatory Commission Expenses	6,081,192	5,838,865
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	274	117
192	(930.2) Miscellaneous General Expenses	3,222,988	3,108,307
193	(931) Rents	873,738	927,319
194	TOTAL Operation (Enter Total of lines 181 thru 193)	58,390,420	55,197,583
195	Maintenance		
196	(935) Maintenance of General Plant	9,552,147	8,858,776
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	67,942,567	64,056,359
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	635,399,996	684,482,695

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	04/15/2015	End of 2014/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	LF	Tariff 8			
7	Bonneville Power Administration	OS	BPA OATT			
8	Bonneville Power Administration	LF	BPA OATT			
9	Brookfield Energy Marketing LP	SF	WSPP			
10	Calpine Energy Services LP	SF	WSPP			
11	Cargill Power Markets	SF	WSPP			
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	04/15/2015	End of 2014/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.
					25,760	25,760	1
60,256				2,137,093		2,137,093	2
2,200				70,450		70,450	3
360,076				14,986,089		14,986,089	4
220,569				6,415,536		6,415,536	5
18,747				648,547		648,547	6
					25,531	25,531	7
2,036				62,274	42,615	104,889	8
800				38,000		38,000	9
38,134				1,428,325		1,428,325	10
46,698				1,322,245		1,322,245	11
46,280				2,158,352		2,158,352	12
132,722				6,389,462		6,389,462	13
-14,444							14
5,979,279	539,911	539,679	17,207,484	177,455,809	3,027,874	197,691,167	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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	Deep Creek Energy, LLC	IU	PURPA			
6	Douglas County PUD No. 1	LU	Wells			
7	Douglas County PUD No. 1	LU	Wells Settlement			
8	Douglas County PUD No. 1	IF	Wells			
9	Douglas County PUD No. 1	SF	WSPP			
10	Douglas County PUD No. 1	EX	305			
11	EDF Trading No America	SF	WSPP			
12	Eugene Water & Electric Board	SF	WSPP			
13	Exelon Generation Company, LLC	SF	WSPP			
14	Ford Hydro Limited Partnership	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	04/15/2015	End of 2014/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 totalied 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)	
6,065				159,322		159,322	1
277,387			12,320,464			12,320,464	2
13,255				380,654		380,654	3
486				11,304		11,304	4
148				5,328		5,328	5
132,515				1,678,001		1,678,001	6
36,952				1,081,290		1,081,290	7
178,554			4,886,770			4,886,770	8
26,555				809,432		809,432	9
	86,940	86,940		1,221,000	-437	1,220,563	10
17,000				515,590		515,590	11
14,366				353,577		353,577	12
17,267				533,570		533,570	13
3,419				232,849		232,849	14
5,979,279	539,911	539,679	17,207,484	177,455,809	3,027,874	197,691,167	

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	04/15/2015	End of 2014/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	Grant County PUD No. 2	LU	Priest Rapids			
2	Grant County PUD No. 2	SF	WSPP			
3	Grant County PUD No. 2	EX	FERC #104			
4	Grant County PUD No. 2	SF	WSPP			
5	Gridforce Energy Management, LLC	SF	NWPP			
6	Hydro Technology Systems	IU	PURPA			
7	Iberdrola Renewables LLC	SF	WSPP			
8	Idaho County Power & Light	LU	PURPA			
9	Idaho Power Company	SF	WSPP			
10	Idaho Power Company - Balancing	SF	WSPP			
11	Inland Power & Light Company	RQ	208			
12	J. Aron & Company	SF	WSPP			
13	Jim White	LU	PURPA			
14	J P Morgan Ventures Energy LLC	SF	WSPP			
	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	04/15/2015	End of 2014/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)	
266,111				6,818,251		6,818,251	1
16,500				439,966		439,966	2
					10,255	10,255	3
			100			100	4
6				204		204	5
9,132				405,298		405,298	6
128,229				3,526,687		3,526,687	7
3,024				139,449		139,449	8
332,980				13,111,032		13,111,032	9
2,038				21,250		21,250	10
65				4,287		4,287	11
800				53,300		53,300	12
1,155				110,678		110,678	13
5,475				46,601		46,601	14
5,979,279	539,911	539,679	17,207,484	177,455,809	3,027,874	197,691,167	

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	04/15/2015	End of 2014/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.

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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.

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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	LU	PPM Energy			
2	Kootenai Electric Cooperative	IU	PURPA			
3	Kootenai Electric Cooperative	LF	Tariff 8			
4	Macquarie Energy LLC	SF	WSPP			
5	Mizuho Securities USA, Inc.	SF	ISDA			
6	Morgan Stanley Capital Group	SF	WSPP			
7	SG Americas Securities, LLC	SF	ISDA			
8	NextEra Energy Power Marketing LLC	SF	WSPP			
9	NorthWestern Energy LLC	SF	WSPP			
10	Okanogan County PUD No. 1	SF	WSPP			
11	PPL Energy Plus	SF	WSPP			
12	PacifiCorp	SF	WSPP			
13	Palouse Wind LLC	LU	PPA			
14	Pend Oreille County PUD No. 1	SF	Pend O'			
	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	04/15/2015	End of 2014/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)	
19,298				866,094		866,094	1
2,350				64,991		64,991	2
701				20,398		20,398	3
33,853				984,872		984,872	4
					1,008,581	1,008,581	5
70,688				1,748,435		1,748,435	6
					895,786	895,786	7
40,974				1,281,698		1,281,698	8
7,953				214,126		214,126	9
22,330				519,193		519,193	10
989,072				32,679,119		32,679,119	11
110,504				3,348,188		3,348,188	12
335,291				18,786,355		18,786,355	13
189,219				5,724,136		5,724,136	14
5,979,279	539,911	539,679	17,207,484	177,455,809	3,027,874	197,691,167	

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	04/15/2015	End of 2014/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	Pend Oreille County PUD No. 1	IF	Pend O'			
2	Phillips Ranch	LU	PURPA			
3	Portland General Electric Company	EX	304			
4	Portland General Electric Company	EX	178			
5	Portland General Electric Company	SF	WSPP			
6	Powerex Corp	SF	WSPP			
7	Puget Sound Energy	SF	WSPP			
8	Rainbow Energy Marketing Corp	SF	WSPP			
9	Rathdrum Power LLC	LF	Lancaster			
10	Sacramento Municipal Utility District	SF	WSPP			
11	Seattle City Light	SF	WSPP			
12	Sheep Creek Hydro	LU	PURPA			
13	Shell Energy	SF	WSPP			
14	Snohomish County PUD No. 1	SF	WSPP			
	Total					

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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)	
13,883	870	1,009		327,050	-5,466	321,584	1
41				1,988		1,988	2
	442,125	441,100					3
	9,976	9,767			98,298	98,298	4
44,415				1,632,617		1,632,617	5
62,099				2,856,483		2,856,483	6
60,183				1,690,194		1,690,194	7
24,820				919,711		919,711	8
1,194,990				24,730,738		24,730,738	9
1,600				64,200		64,200	10
29,714				925,823		925,823	11
7,218				373,573		373,573	12
47,796				1,362,458		1,362,458	13
39,759				974,904		974,904	14
5,979,279	539,911	539,679	17,207,484	177,455,809	3,027,874	197,691,167	

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	04/15/2015	End of 2014/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	Southern California Edison Company	SF	WSPP			
2	Sovereign Power	LF	Sovereign			
3	Spokane County	LU	PURPA			
4	Stimson Lumber	IU	PURPA			
5	Tacoma Power	SF	WSPP			
6	Tacoma Power	SF	WSPP			
7	Tenaska Power Services Company	SF	WSPP			
8	The Energy Authority	SF	WSPP			
9	TransAlta Energy Marketing	SF	WSPP			
10	Tri-State Generation & Transmission	SF	WSPP			
11	IntraCompany Generation Services	OS	OATT			
12	Other - Inadvertent Interchange	EX				
13						
14						
	Total					

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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)	
3,510				72,680		72,680	1
6,835				159,289		159,289	2
1,412				90,374		90,374	3
30,311				1,654,423		1,654,423	4
46,120				1,540,100		1,540,100	5
			150			150	6
10,327				366,066		366,066	7
28,578				734,289		734,289	8
99,870				3,425,951		3,425,951	9
7							10
					926,951	926,951	11
		863					12
							13
							14
5,979,279	539,911	539,679	17,207,484	177,455,809	3,027,874	197,691,167	

FOOTNOTE DATA

Schedule Page: 326 Line No.: 1 Column: a
Fianncial SWAP
Schedule Page: 326 Line No.: 4 Column: a
BPA Contract Terminates June 30, 2019
Schedule Page: 326 Line No.: 6 Column: a
BPA Contract Terminates September 30, 2028
Schedule Page: 326 Line No.: 7 Column: a
Ancillary Services - Spinning & Supplemental
Schedule Page: 326 Line No.: 8 Column: a
BPA Contract Terminates January 01,2036
Schedule Page: 326 Line No.: 8 Column: l
Non Monetary
Schedule Page: 326.1 Line No.: 10 Column: l
Non Monetary
Schedule Page: 326.2 Line No.: 3 Column: l
Non Monetary
Schedule Page: 326.2 Line No.: 5 Column: a
Reserve Sharing under the NorthWest Power Pool Reserve Sharing Agreement.
Schedule Page: 326.2 Line No.: 11 Column: a
Service to Deer Lake from Inland Power and Light. No demand charges associated with the agreement.
Schedule Page: 326.3 Line No.: 3 Column: a
Kootenai Contract Terminates March 31, 2019
Schedule Page: 326.3 Line No.: 5 Column: a
Financial SWAP
Schedule Page: 326.3 Line No.: 7 Column: a
Financial SWAP - Formerly known as Newedge USA, LLC
Schedule Page: 326.4 Line No.: 1 Column: l
Non Monetary
Schedule Page: 326.4 Line No.: 4 Column: l
Non Monetary
Schedule Page: 326.5 Line No.: 2 Column: a
Sovereign Contract Terminates September 30, 2019
Schedule Page: 326.5 Line No.: 11 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	04/15/2015	End of 2014/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 Power	Tacoma Power	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	East Greenacres Irrigation District	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	Shell Energy North America (US) LP	Avista Corporation	Idaho Power Company	SFP
16	Shell Energy North America (US) LP	Bonneville Power Administration	Idaho Power Company	SFP
17	Shell Energy North America (US) LP	Avista Corporation	Bonneville Power Administration	SFP
18	Cargill Power Markets	Bonneville Power Administration	Idaho Power Company	SFP
19	Morgan Stanley Capital Group	Avista Corporation	Bonneville Power Administration	SFP
20	Morgan Stanley Capital Group	Bonneville Power Administration	Idaho Power Company	SFP
21	Morgan Stanley Capital Group	Bonneville Power Administration	Northwestern Montana	SFP
22	Morgan Stanley Capital Group	Northwestern Montana	Avista Corporation	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	Portland General Electric	SFP
27	Morgan Stanley Capital Group	Northwestern Montana	Grant County PUD	SFP
28	Morgan Stanley Capital Group	Puget Sound Energy	Idaho Power Company	SFP
29	Morgan Stanley Capital Group	Grant County PUD	Bonneville Power Administration	SFP
30	Morgan Stanley Capital Group	Grant County PUD	Idaho Power Company	SFP
31	Morgan Stanley Capital Group	Grant County PUD	Northwestern Montana	SFP
32	Morgan Stanley Capital Group	Chelan County PUD	Idaho Power Company	SFP
33	Morgan Stanley Capital Group	Chelan County PUD	Northwestern Montana	SFP
34	Bonneville Power Administration	Bonneville Power Adminstration	Idaho Power Company	SFP
	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	04/15/2015	End of 2014/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	66,615	66,615	1
FERC Trf No. 8	Chelan-Stratford 115	Stratford 115kV SS		256,758	256,758	2
FERC Trf No. 8	Chelan-Stratford 115	Stratford 115kV SS		256,750	256,750	3
FERC No. 104	Stratford Substation	Coulee Cy/Wilson Crk	25	94,504	94,504	4
FERC Trf No. 8	Westside	Little Falls	1	3,080	3,080	5
FERC Trf No. 8	Bell Substation	Post Falls	3	3,070	3,070	6
FERC Trf No. 8	Bell Substation	BKR/OPT/EFM/LIB	3	6,817	6,817	7
FERC Trf No. 8				1,871,991	1,871,991	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				37,514	37,514	15
FERC Trf No. 8				39,466	39,466	16
FERC Trf No. 8				128	128	17
FERC Trf No. 8				2,432	2,432	18
FERC Trf No. 8				151	151	19
FERC Trf No. 8				9,122	9,122	20
FERC Trf No. 8				414	414	21
FERC Trf No. 8				1,688	1,688	22
FERC Trf No. 8				146,818	146,818	23
FERC Trf No. 8				11,393	11,393	24
FERC Trf No. 8				6,776	6,776	25
FERC Trf No. 8				288	288	26
FERC Trf No. 8				31,042	31,042	27
FERC Trf No. 8				15	15	28
FERC Trf No. 8				3,177	3,177	29
FERC Trf No. 8				155	155	30
FERC Trf No. 8				6,343	6,343	31
FERC Trf No. 8				365	365	32
FERC Trf No. 8				4,515	4,515	33
FERC Trf No. 8				2,567	2,567	34
			55	3,177,883	3,177,883	

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	04/15/2015	End of 2014/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.
231,694			231,694	1
144,871		37,116	181,987	2
179,355		37,116	216,471	3
		25,164	25,164	4
		32,682	32,682	5
16,593			16,593	6
38,837			38,837	7
7,284,870			7,284,870	8
		27,973	27,973	9
		9,480	9,480	10
		6,120	6,120	11
		200,000	200,000	12
		603	603	13
		3,192,000	3,192,000	14
152,516			152,516	15
181,432			181,432	16
455			455	17
14,307			14,307	18
698			698	19
70,105			70,105	20
1,791			1,791	21
7,725			7,725	22
713,318			713,318	23
62,602			62,602	24
41,713			41,713	25
1,078			1,078	26
127,838			127,838	27
59			59	28
29,109			29,109	29
850			850	30
53,801			53,801	31
1,577			1,577	32
19,847			19,847	33
10,153			10,153	34
11,153,220	**0**	**3,592,760**	**14,745,980**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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 Classifi-cation (d)
1	Idaho Power Company LSE	Avista Corporation	Bonneville Power Administration	SFP
2	Idaho Power Company LSE	Avista Corporation	Idaho Power Company	SFP
3	Idaho Power Company LSE	Bonneville Power Administration	Idaho Power Company	SFP
4	Idaho Power Company LSE	Bonneville Power Administration	Northwestern Montana	SFP
5	Idaho Power Company LSE	Bonneville Power Administration	Pacificorp	SFP
6	Idaho Power Company LSE	Northwestern Montana	Idaho Power Company	SFP
7	Idaho Power Company LSE	Pacificorp	Idaho Power Company	SFP
8	Idaho Power Company LSE	Idaho Power Company	Bonneville Power Administration	SFP
9	Idaho Power Company LSE	Chelan County PUD	Northwestern Montana	SFP
10	Kootenai Electric	Avista Corporation	Idaho Power Company	SFP
11	Bonneville Power Administration	Bonneville Power Administration	Avista Corporation	NF
12	Bonneville Power Administration	Bonneville Power Administration	Idaho Power Company	NF
13	Shell Energy North America (US) LP	Avista Corporation	Bonneville Power Administration	NF
14	Shell Energy North America (US) LP	Avista Corporation	Idaho Power Company	NF
15	Shell Energy North America (US) LP	Bonneville Power Administration	Chelan County PUD	NF
16	Shell Energy North America (US) LP	Bonneville Power Administration	Idaho Power Company	NF
17	Shell Energy North America (US) LP	Bonneville Power Administration	Northwestern Montana	NF
18	Shell Energy North America (US) LP	Northwestern Montana	Bonneville Power Administration	NF
19	Shell Energy North America (US) LP	Northwestern Montana	Chelan County PUD	NF
20	Shell Energy North America (US) LP	Northwestern Montana	Grant County PUD	NF
21	Shell Energy North America (US) LP	Idaho Power Company	Bonneville Power Administration	NF
22	Cargill Power Markets	Avista Corporation	Bonneville Power Administration	NF
23	Cargill Power Markets	Bonneville Power Administration	Idaho Power Company	NF
24	Cargill Power Markets	Northwestern Montana	Idaho Power Company	NF
25	PPL Energy Plus	Bonneville Power Administration	Northwestern Montana	NF
26	PPL Energy Plus	Northwestern Montana	Bonneville Power Administration	NF
27	PPL Energy Plus	Northwestern Montana	Idaho Power Company	NF
28	Morgan Stanley Capital Group	Bonneville Power Administration	Idaho Power Company	NF
29	Morgan Stanley Capital Group	Bonneville Power Administration	Northwestern Montana	NF
30	Morgan Stanley Capital Group	Northwestern Montana	Avista Corporation	NF
31	Morgan Stanley Capital Group	Northwestern Montana	Bonneville Power Administration	NF
32	Morgan Stanley Capital Group	Northwestern Montana	Chelan County PUD	NF
33	Morgan Stanley Capital Group	Northwestern Montana	Idaho Power Company	NF
34	Morgan Stanley Capital Group	Grant County PUD	Idaho Power Company	NF
	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	04/15/2015	End of 2014/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				3,200	3,200	1
FERC Trf No. 8				3,000	3,000	2
FERC Trf No. 8				130,156	130,156	3
FERC Trf No. 8				8,880	8,880	4
FERC Trf No. 8				3,400	3,400	5
FERC Trf No. 8				8,842	8,842	6
FERC Trf No. 8				33,645	33,645	7
FERC Trf No. 8				10,796	10,796	8
FERC Trf No. 8				636	636	9
FERC Trf No. 8			3	5,882	5,882	10
FERC Trf No. 8						11
FERC Trf No. 8				3,992	3,992	12
FERC Trf No. 8				40	40	13
FERC Trf No. 8				448	448	14
FERC Trf No. 8				4	4	15
FERC Trf No. 8				6,285	6,285	16
FERC Trf No. 8				372	372	17
FERC Trf No. 8				6,084	6,084	18
FERC Trf No. 8				54	54	19
FERC Trf No. 8				161	161	20
FERC Trf No. 8				18	18	21
FERC Trf No. 8				75	75	22
FERC Trf No. 8				898	898	23
FERC Trf No. 8				25	25	24
FERC Trf No. 8				313	313	25
FERC Trf No. 8				480	480	26
FERC Trf No. 8				4,095	4,095	27
FERC Trf No. 8				887	887	28
FERC Trf No. 8				1,850	1,850	29
FERC Trf No.8				40	40	30
FERC Trf No. 8				22,638	22,638	31
FERC Trf No. 8				186	186	32
FERC Trf No. 8				862	862	33
FERC Trf No. 8				10	10	34
			55	**3,177,883**	**3,177,883**	

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	04/15/2015	End of 2014/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.
10,267			10,267	1
10,007			10,007	2
525,643			525,643	3
73,634			73,634	4
33,361			33,361	5
29,640			29,640	6
198,440			198,440	7
54,646			54,646	8
6,240			6,240	9
48,000		24,506	72,506	10
23			23	11
24,476			24,476	12
215			215	13
2,905			2,905	14
205			205	15
38,320			38,320	16
3,309			3,309	17
39,989			39,989	18
312			312	19
929			929	20
108			108	21
433			433	22
7,945			7,945	23
144			144	24
1,893			1,893	25
2,829			2,829	26
23,707			23,707	27
13,506			13,506	28
13,281			13,281	29
290			290	30
143,211			143,211	31
1,447			1,447	32
6,685			6,685	33
122			122	34
11,153,220	**0**	**3,592,760**	**14,745,980**	

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	04/15/2015	End of 2014/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	Morgan Stanley Capital Group	Chelan County PUD	Idaho Power Company	NF
2	NaturEner USA, LLC	Bonneville Power Administration	Northwestern Montana	NF
3	Northwestern Energy	Bonneville Power Administration	Northwestern Montana	NF
4	Northwestern Energy	Northwestern Montana	Bonneville Power Administration	NF
5	Portland General Electric	Northwestern Montana	Bonneville Power Administration	NF
6	Portland General Electric	Northwestern Montana	Portland General Electric	NF
7	PPM Energy Inc.	Bonneville Power Administration	Idaho Power Company	NF
8	Puget Sound Energy	Northwestern Montana	Bonneville Power Administration	NF
9	Puget Sound Energy	Northwestern Montana	Idaho Power Company	NF
10	Puget Sound Energy	Northwestern Montana	Puget Sound Energy	NF
11	Puget Sound Energy	Idaho Power Company	Avista Corporation	NF
12	Puget Sound Energy	Idaho Power Company	Bonneville Power Administration	NF
13	Powerex	Bonneville Power Administration	Idaho Power Company	NF
14	Powerex	Bonneville Power Administration	Northwestern Montana	NF
15	Powerex	Northwestern Montana	Bonneville Power Administration	NF
16	Powerex	Chelan County PUD	Idaho Power Company	NF
17	Rainbow	Northwestern Montana	Bonneville Power Administration	NF
18	Transalta Energy Marketing	Avista Corporation	Bonneville Power Adminstration	NF
19	Tenaska Power Services	Bonneville Power Administration	Idaho Power Company	NF
20	Tenaska Power Services	Northwestern Montana	Bonneville Power Administration	NF
21	Pacificorp	Pacificorp	Bonneville Power Administration	NF
22	Pacificorp	Pacificorp	Idaho Power Company	NF
23	Pacificorp	Idaho Power Company	Bonneville Power Administration	NF
24	Grant County PUD	Avista Corporation	Grant County PUD	NF
25	Bonneville Power Administration	Bonneville Power Administration	Idaho Power Company	NF
26	Idaho Power Company	Bonneville Power Administration	Idaho Power Company	NF
27	Idaho Power Company	Northwestern Montana	Idaho Power Company	NF
28	Idaho Power Company LSE	Bonneville Power Administration	Idaho Power Company	NF
29	Idaho Power Company LSE	Northwestern Montana	Idaho Power Company	NF
30	Idaho Power Company LSE	Pacificorp	Idaho Power Company	NF
31	Idaho Power Company LSE	Idaho Power Company	Bonneville Power Administration	NF
32	The Energy Authority	Northwestern Montana	Bonneville Power Administration	NF
33	Seattle City Light	Northwestern Montana	Bonneville Power Administration	NF
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	04/15/2015	End of 2014/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				7	7	1
FERC Trf No. 8						2
FERC Trf No. 8				795	795	3
FERC Trf No. 8				396	396	4
FERC Trf No. 8				4,140	4,140	5
FERC Trf No. 8				1,815	1,815	6
FERC Trf No. 8				613	613	7
FERC Trf No. 8				5,154	5,154	8
FERC Trf No. 8				1,357	1,357	9
FERC Trf No. 8				8	8	10
FERC Trf No. 8						11
FERC Trf No. 8				672	672	12
FERC Trf No. 8				896	896	13
FERC Trf No. 8				79	79	14
FERC Trf No. 8				671	671	15
FERC Trf No. 8				1	1	16
FERC Trf No. 8				50	50	17
FERC Trf No. 8				95	95	18
FERC Trf No. 8				110	110	19
FERC Trf No. 8				11	11	20
FERC Trf No. 8				3,350	3,350	21
FERC Trf No. 8				4,996	4,996	22
FERC Trf No. 8				123	123	23
FERC Trf No. 8						24
FERC Trf No. 8				2,003	2,003	25
FERC Trf No. 8				720	720	26
FERC Trf No. 8				576	576	27
FERC Trf No. 8				18,513	18,513	28
FERC Trf No. 8				2,485	2,485	29
FERC Trf No. 8				5,689	5,689	30
FERC Trf No. 8				200	200	31
FERC Trf No. 8				105	105	32
FERC Trf No. 8				45	45	33
						34
			55	**3,177,883**	**3,177,883**	

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	04/15/2015	End of 2014/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.
86			86	1
6			6	2
4,651			4,651	3
2,925			2,925	4
26,390			26,390	5
10,482			10,482	6
3,906			3,906	7
35,699			35,699	8
9,478			9,478	9
46			46	10
6			6	11
4,693			4,693	12
6,943			6,943	13
456			456	14
5,628			5,628	15
7			7	16
289			289	17
548			548	18
1,062			1,062	19
289			289	20
53,210			53,210	21
69,368			69,368	22
1,990			1,990	23
3,935			3,935	24
13,496			13,496	25
4,154			4,154	26
3,324			3,324	27
112,666			112,666	28
22,456			22,456	29
48,534			48,534	30
2,189			2,189	31
692			692	32
260			260	33
				34
11,153,220	**0**	**3,592,760**	**14,745,980**	

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.: 4 Column: m
Use of facilities.

Schedule Page: 328 Line No.: 5 Column: m
Long term firm transmission and ancillary services.

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

Schedule Page: 328.1 Line No.: 10 Column: m
Ancillary services.

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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			1,499,435			1,499,435
2	Bonneville Power Admin	LFP			11,774,320		2,060,112	13,834,432
3	Bonneville Power Admin	LFP			943,401			943,401
4	Bonneville Power Admin	OS					24,360	24,360
5	Bonneville Power Admin	FNS			1,105,330		195,624	1,300,954
6	Bonneville Power Admin	NF	3,319	3,319		16,595		16,595
7	Benton County PUD No. 1	NF	310	310		449		449
8	Grays Harbor County PUD	NF	50	50		62		62
9	Idaho Power Company	NF	800	800		1,986		1,986
10	Kootenai Electric Coop	LFP			45,222			45,222
11	Northern Lights	LFP			140,005			140,005
12	NorthWestern Energy	SFP			225,260		21,106	246,366
13	NorthWestern Energy	NF	43,824	43,824		189,758		189,758
14	Portland General Elec	LFP			628,000		14,989	642,989
15	Portland General Elec	NF	1,890	1,890		2,646		2,646
16	Seattle City Light	NF	4,268	4,268		6,521		6,521
	TOTAL		55,102	55,102	16,360,973	218,858	2,316,191	18,896,022

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	04/15/2015	End of 2014/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)	TRANSFER OF ENERGY: 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	Snohomish County PUD	NF	641	641		841		841
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		55,102	55,102	16,360,973	218,858	2,316,191	18,896,022

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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	04/15/2015	End of 2014/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	579,854
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	300,139
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Community relations	15,317
7	Director fees and expenses	862,480
8	Educational and informational expenses	47,670
9	Rating agency fees	165,749
10	Aircraft operations and fees	158,445
11	Other miscellaneous general expenses	1,093,334
12		
13		
14		
15		
16		
17		
18		
19		
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		
45		
46	TOTAL	3,222,988

Name of Respondent Avista Corporation	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report 2014/Q4

FOOTNOTE DATA

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

Other miscellaneous general expenses, detail:

VENDOR	PURPOSE	AMOUNT
Citibank	Miscellaneous	$ 11,419
Citibank NA	Misc.	$ 40,134
Clean Tech Alliance Washington	Misc.	$ 5,000
Corp credit card	Misc.	$ 69,698
E Source Companies LLC	Misc.	$ 5,169
Enterprise Rent a Car	Misc.	$ 3,997
EPRI	Misc.	$ 9,217
Hanna & Associates Inc.	Professional services	$ 162,050
Intelliresponse System Inc.	Misc.	$ 55,963
Klundt Hosmer Design	Prof. svcs.	$ 16,690
Marketwire Inc.	Misc.	$ 7,362
Newsdata Corporation	Misc.	$ 17,048
Olsten	Workforce contract	$ 23,005
Raidious LLC	Misc.	$ 13,579
Sarah Dennison Leonard	Misc.	$ 3,921
Thackston, Jason R.	Employee misc expenses	$ 9,684
The Bank of New York Mellon	Misc.	$ 6,272
The Coeur d'Alene	Misc.	$ 10,774
The Davenport Hotel	Misc.	$ 9,426
Union Bank of California	Misc.	$ 37,071
Wilmington Trust Company	Misc.	$ 3,565
Wurts & Associates Inc.	Misc.	$ 25,546

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	04/15/2015	End of 2014/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			2,152,976		2,152,976
2	Steam Production Plant	7,783,468				7,783,468
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	8,250,380				8,250,380
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	9,350,009			2,450,031	11,800,040
7	Transmission Plant	10,392,803				10,392,803
8	Distribution Plant	38,330,263				38,330,263
9	Regional Transmission and Market Operation					
10	General Plant	3,844,682				3,844,682
11	Common Plant-Electric	11,145,806		8,405,480		19,551,286
12	TOTAL	89,097,411		10,558,456	2,450,031	102,105,898

B. Basis for Amortization Charges

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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	51,637	70.00	-10.00	1.56	S1.5	22.10
15	312	79,412	60.00	-10.00	1.93	R1	21.50
16	313	3					
17	314	26,713	40.00	-5.00	2.79	R0.5	19.40
18	315	9,543	50.00		1.73	R3	21.00
19	316	9,837	53.00		1.46	R2	20.90
20	Subtotal	177,145					
21							
22	Colstrip No. 4						
23	311	51,379	70.00	-10.00	1.68	S1.5	23.90
24	312	51,994	60.00	-10.00	2.20	R1	23.30
25	313	3					
26	314	13,466	40.00	-5.00	2.88	R0.5	20.90
27	315	6,673	50.00		1.88	R3	22.90
28	316	4,551	53.00		1.62	R2	22.70
29	Subtotal	128,066					
30							
31	Kettle Falls					0	
32	310	148			1.45	SQ	18.00
33	311	25,219	70.00	-10.00	1.51	S1.5	17.10
34	312	43,722	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	10,929	50.00		1.56	R3	16.40
37	316	2,601	53.00		1.74	R2	16.80
38	Subtotal	95,964					
39							
40	HYDRO PLANT						
41	Cabinet Gorge						
42	330	7,842	100.00		2.00	R4	43.20
43	331	12,265	110.00	-20.00	1.50	R2	51.50
44	332	36,762	100.00		1.13	R1	47.70
45	333	37,880	65.00	-10.00	2.04	R1.5	43.90
46	334	6,026	38.00	-5.00	2.97	R2.5	19.70
47	335	4,550	65.00		0.38	R1.5	49.90
48	336	1,261	55.00		1.96	S2	19.00
49	Subtotal	106,586					
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	04/15/2015	End of 2014/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	16,774	110.00	-20.00	1.48	R2	58.40
15	332	34,023	100.00		1.12	R1	52.60
16	333	88,366	65.00	-10.00	1.98	R1.5	47.50
17	334	14,257	38.00	-5.00	2.79	R2.5	29.50
18	335	3,443	65.00		0.80	R1.5	53.60
19	336	247	55.00		1.89	S2	32.00
20	Subtotal	187,516					
21							
22	Post Falls						
23	330	2,908	75.00		2.81	R3	25.20
24	331	1,591	110.00	-20.00	2.09	R2	45.60
25	332	12,716	100.00		1.71	R1	44.70
26	333	2,234	65.00	-10.00	2.42	R1.5	29.60
27	334	718	38.00	-5.00	2.78	R2.5	18.20
28	335	223	65.00		1.15	R1.5	42.10
29	Subtotal	20,390					
30							
31	Long Lake						
32	330	418	75.00		4.42	R3	11.00
33	331	4,474	110.00	-20.00	1.99	R2	38.90
34	332	18,065	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	35,146					
39							
40	Little Falls						
41	330	4,218	100.00		3.35	R4	24.40
42	331	1,943	110.00	-20.00	1.94	R2	42.30
43	332	5,059	100.00		1.72	R1	43.60
44	333	3,878	65.00	-10.00	2.40	R1.5	33.60
45	334	4,967	38.00	-5.00	2.74	R2.5	22.20
46	335	134	65.00		0.69	R1.5	40.60
47	Subtotal	20,199					
48							
49	Upper Falls						
50	330	64	100.00		3.66	R4	22.20

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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	331	978	110.00	-20.00	1.77	R2	41.40
13	332	7,657	100.00		1.85	R1	45.20
14	333	1,186	65.00	-10.00	2.53	R1.5	30.00
15	334	4,269	38.00	-5.00	2.81	R2.5	35.10
16	335	107	65.00		1.05	R1.5	41.20
17	336	490	55.00		1.94	S2	26.20
18	Subtotal	14,751					
19							
20	Nine Mile						
21	330	11	100.00		2.48	R4	35.90
22	331	6,700	110.00	-20.00	1.98	R2	46.50
23	332	13,595	100.00		1.83	R1	45.10
24	333	14,382	65.00	-10.00	2.17	R1.5	40.30
25	334	3,339	38.00	-5.00	2.80	R2.5	22.50
26	335	276	65.00		0.88	R1.5	41.20
27	336	625	55.00		1.93	S2	36.20
28	Subtotal	38,928					
29							
30	Monroe Street						
31	331	11,984	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	1,683	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	34,760					
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

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	48,853	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	62,756					
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	30,610	45.00		2.94	R1	26.90
31	345	646	20.00	-5.00	6.03	S2	14.30
32	346	48	35.00		2.87	R3	26.20
33	Subtotal	32,682					
34							
35	Coyote Springs 2						
36	341	11,377	55.00		2.34	S4	32.80
37	342	19,227	55.00	-10.00	2.72	R3	31.40
38	344	125,719	45.00		3.00	R1	27.90
39	345	15,855	20.00	-5.00	6.14	S2	13.40
40	346	956	35.00		2.95	R3	27.40
41	Subtotal	173,134					
42							
43	Solar Power	183	25.00		5.30	S2.5	17.90
44	Subtotal	183					
45							
46	Lancaster						
47	342	141	55.00	-10.00	3.67	R3	29.40
48	344	209	45.00		3.70	R1	26.60
49	Subtotal	350					
50							

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	17,173	75.00		1.30	R4	56.80
14	352	20,483	60.00	-5.00	1.65	S2	48.00
15	353	232,782	45.00	-10.00	2.33	R2.5	33.10
16	354	17,126	70.00	-15.00	1.80	R4	41.00
17	355	179,710	65.00	-15.00	1.38	R2.5	54.70
18	356	125,521	65.00	-10.00	1.59	R2.5	50.20
19	357	2,973	60.00		1.64	R4	51.70
20	358	2,330	50.00		2.02	S2	35.40
21	359	1,952	65.00		1.66	R4	39.70
22	362	111					
23	Subtotal	600,161					
24							
25	DISTRIBUTION PLANT						
26	360	2,537	75.00		1.34	R4	74.40
27	361	18,851	60.00	-10.00	1.62	R2.5	47.30
28	362	122,474	45.00		1.97	R1.5	34.20
29	364	307,105	55.00	-25.00	2.31	R2.5	41.10
30	365	197,954	50.00	-20.00	2.82	R3	32.70
31	366	91,963	50.00	-25.00	2.71	S2	37.60
32	367	160,184	28.00	-20.00	5.63	S2	16.80
33	368	219,389	44.00	-5.00	2.11	R2	33.00
34	369	142,839	55.00	-40.00	2.70	R4	37.55
35	370.2 - ID	21,910	15.00		7.65	S2.5	12.50
36	370.3 - WA	26,313	35.00		3.39	S0.5	23.60
37	373	17,654	35.00	-25.00	1.91	R2.5	26.45
38	373.4	22,690	35.00	-25.00	3.48	R2.5	26.80
39	Subtotal	1,351,863					
40							
41	GENERAL PLANT						
42	390.1	7,445	48.00	-5.00	1.67	S2	39.00
43	391.1	8,929	5.00		21.28	SQ	3.30
44	393	395	25.00		4.58	SQ	19.40
45	394	3,008	20.00		4.78	SQ	10.20
46	395	678	15.00		13.73	SQ	4.00
47	397	57,690	15.00		2.81	SQ	11.70
48	398	81	10.00		13.31	SQ	7.00
49	Subtotal	78,226					
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	04/15/2015	End of 2014/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	MISC POWER						
13	392	4,718	15.00	20.00	1.83	L2.5	13.70
14	396	2,995	16.00	5.00	5.79	S0.5	11.80
15	Subtotal	7,713					
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26	TOTAL COMPANY	3,189,779					
27							
28							
29							
30							
31							
32							
33							
34							
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36							
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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	04/15/2015	End of 2014/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.	2,156,360	472,828	2,629,188	
5					
6					
7					
8					
9	Washington Utilities and Transportation				
10	Commission: includes annual fee and various				
11	other electric dockets	997,195	909,098	1,906,293	
12					
13	Includes annual fee and various other natural				
14	gas dockets	314,536	282,397	596,933	
15					
16	Idaho Public Utilities Commission				
17	Includes annual fee and various other electric				
18	dockets	590,379	244,404	834,783	
19					
20	Includes annual fee and various other natural				
21	gas dockets	161,525	71,788	233,313	
22					
23	Public Utility Commission of Oregon				
24	Includes annual fees and various other natural				
25	gas dockets	549,812	415,815	965,627	
26					
27	Not directly assigned electric		710,928	710,928	
28	Not directly assigned natural gas		285,657	285,657	
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	4,769,807	3,392,915	8,162,722	

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							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
							2
							3
Electric	928	2,629,188					4
							5
							6
							7
							8
							9
							10
Electric	928	1,906,293					11
							12
							13
Gas	928	596,933					14
							15
							16
							17
Electric	928	834,783					18
							19
							20
Gas	928	233,313					21
							22
							23
							24
Gas	928	965,627					25
							26
Electric	928	710,928					27
Gas	928	285,657					28
							29
							30
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							45
		8,162,722					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	04/15/2015	End of 2014/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & 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) and Battery Storage
2		
3		
4		
5		
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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) 04/15/2015	Year/Period of Report End of 2014/Q4

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.
633,270	1,075,557	107	1,708,827		1
182		108	182		2
12,621	4,937	580	17,558		3
372		584	372		4
11		585	11		5
3	5,080	587	5,083		6
23,756	528,615	588	552,371		7
390		903	390		8
117,369		920	117,369		9
61,264	37,213	921	98,477		10
	11,964	923	11,964		11
201	198,320	935	198,521		12
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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	04/15/2015	End of 2014/Q4

DISTRIBUTION OF SALARIES AND WAGES

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

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	10,113,212		
4	Transmission	2,951,554		
5	Regional Market			
6	Distribution	7,946,431		
7	Customer Accounts	6,799,031		
8	Customer Service and Informational	670,845		
9	Sales			
10	Administrative and General	15,754,826		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	44,235,899		
12	Maintenance			
13	Production	3,442,184		
14	Transmission	1,139,156		
15	Regional Market			
16	Distribution	4,148,919		
17	Administrative and General			
18	TOTAL Maintenance (Total of lines 13 thru 17)	8,730,259		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	13,555,396		
21	Transmission (Enter Total of lines 4 and 14)	4,090,710		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	12,095,350		
24	Customer Accounts (Transcribe from line 7)	6,799,031		
25	Customer Service and Informational (Transcribe from line 8)	670,845		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	15,754,826		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	52,966,158	13,477,288	66,443,446
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply	734,753		
34	Storage, LNG Terminaling and Processing	3,573		
35	Transmission			
36	Distribution	4,754,140		
37	Customer Accounts	2,746,083		
38	Customer Service and Informational	313,752		
39	Sales			
40	Administrative and General	5,981,587		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	14,533,888		
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	1,084,690		

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	04/15/2015	End of 2014/Q4

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	3,472,268		
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	4,556,958		
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)	734,753		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	3,573		
56	Transmission (Lines 35 and 47)	1,084,690		
57	Distribution (Lines 36 and 48)	8,226,408		
58	Customer Accounts (Line 37)	2,746,083		
59	Customer Service and Informational (Line 38)	313,752		
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)	5,981,587		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	19,090,846	4,847,565	23,938,411
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	72,057,004	18,324,853	90,381,857
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	25,103,214	11,855,092	36,958,306
69	Gas Plant	5,564,967	3,639,262	9,204,229
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	30,668,181	15,494,354	46,162,535
72	Plant Removal (By Utility Departments)			
73	Electric Plant	1,759,115	439,344	2,198,459
74	Gas Plant	109,173	27,267	136,440
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	1,868,288	466,611	2,334,899
77	Other Accounts (Specify, provide details in footnote):	41,119,277	-34,285,815	6,833,462
78				
79				
80				
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	41,119,277	-34,285,815	6,833,462
96	TOTAL SALARIES AND WAGES	145,712,750	3	145,712,753

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	04/15/2015	End of 2014/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	70,315,730
389	Land and Land Rights	5,145,059
390	Structures and Improvements	99,113,915
391	Office Furniture and Equipment	45,358,239
392	Transportation Equipment	11,555,328
393	Stores Equipment	2,948,035
394	Tools, Shop & Garage Equipment	10,697,687
395	Laboratory Equipment	427,993
396	Power Operated Equipment	2,174,605
397	Communications Equipment	43,607,502
398	Miscellaneous Equipment	422,352
399	Asset Retirement Cost	0
	Total Common Plant	291,766,445
	Const. Work in Progress	98,730,667
	Total Utility Plant	390,497,112
	Acc. Prov. for Dep. & Amort.	78,657,464
	Net Utility Plant	311,839,648

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	611,894	323,796	288,098	#of cust @ yr end
902	Meter reading expenses	4,596,246	2,830,874	1,765,372	#of cust @ yr end
903	Cust rec and collection expenses	14,864,258	8,099,706	6,764,552	#of cust @ yr end
903.90-99	A/R misc fees	0	0	0	net direct plant
904	Uncollectible accounts	5,200,200	2,751,684	2,448,316	#of cust @ yr end
905	Misc cust acct expenses	372,628	197,186	175,442	#of cust @ yr end
907	Cust svce & Info exp supervision	0	0	0	#of cust @ yr end
908	Cust assistance expenses	1,008,321	620,869	387,452	#of cust @ yr end
909	Info & instruct expenses	1,404,562	862,959	541,603	#of cust @ yr end
910	Misc cust serv & info expenses	336,534	178,084	158,450	#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.

911	Sales expense -supervision	0	0	0	#of cust @ yr end
912	Demo & selling expenses	0	0	0	#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	32,339,456	23,183,815	9,155,641	four factor
921	Office supplies expenses	5,963,582	4,255,274	1,708,308	four factor
922	Admin expenses tranf-credit	0	0	0	four factor
923	Outside services employed	16,225,074	11,569,644	4,655,430	four factor
924	Property insurance	1,648,169	1,174,980	473,189	four factor
925	Injuries and damages	6,471,302	4,765,354	1,705,948	four factor
926	Employee pensions & benefits	51,157,476	36,508,471	14,649,005	four factor
927	Franchise requirement	0	0	0	four factor
928	Regulatory commission expenses	1,886,815	1,411,406	475,409	four factor
929	Duplicate charges-credit	0	0	0	four factor
930.1	General advertising expenses	348	274	74	four factor
930.2	Misc general expenses	3,480,933	2,506,914	974,019	four factor
931	Rents	1,090,655	795,541	295,114	four factor
935	Maint of general plant	11,321,730	8,205,339	3,116,391	four factor
403	Depreciation	15,514,973	11,145,807	4,369,166	four factor
404	Amort of LTD term plant	11,787,413	8,405,480	3,381,933	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
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (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	643	MW	146,836			
2	Reactive Supply and Voltage						
3	Regulation and Frequency Response	57,173	MW/h	6,862	75,079	MW	671,205
4	Energy Imbalance				579	MW	3,352,037
5	Operating Reserve - Spinning	436	MW/h	9,067	170,209	MW/h	1,864,944
6	Operating Reserve - Supplement	446	MW/h	9,167	20,582	MW/h	171,794
7	Other	1,316,794	MW	11,772,142	1,316,794	MW	11,772,142
8	Total (Lines 1 thru 7)	1,375,492		11,944,074	1,583,243		17,832,122

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	2,140	6	900	1,530	310	162	21	138	105
2	February	2,381	6	800	1,731	409	162	18	98	340
3	March	2,211	4	1900	1,323	248	162	15	478	567
4	Total for Quarter 1	6,732			4,584	967	486	54	714	1,012
5	April	2,105	29	800	1,224	236	185	27	460	397
6	May	2,068	16	1100	1,123	200	185	22	560	147
7	June	2,005	3	1600	1,170	216	179	20	440	30
8	Total for Quarter 2	6,178			3,517	652	549	69	1,460	574
9	July	2,598	29	1700	1,602	293	185	34	518	129
10	August	2,238	4	1700	1,552	286	183	34	217	165
11	September	1,975	7	1900	1,248	213	173	24	341	72
12	Total for Quarter 3	6,811			4,402	792	541	92	1,076	366
13	October	1,867	7	1900	1,147	207	176	20	337	283
14	November	2,280	18	800	1,464	318	165	21	333	145
15	December	2,293	30	1900	1,581	344	165	23	203	50
16	Total for Quarter 4	6,440			4,192	869	506	64	873	478
17	Total Year to Date/Year	26,161			16,695	3,280	2,082	279	4,123	2,430

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	04/15/2015	End of 2014/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)
1	SOURCES OF ENERGY	
2	Generation (Excluding Station Use):	
3	Steam	1,723,402
4	Nuclear	
5	Hydro-Conventional	4,143,307
6	Hydro-Pumped Storage	
7	Other	1,528,676
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	7,395,385
10	Purchases	5,979,279
11	Power Exchanges:	
12	Received	539,911
13	Delivered	539,679
14	Net Exchanges (Line 12 minus line 13)	232
15	Transmission For Other (Wheeling)	
16	Received	3,177,883
17	Delivered	3,177,883
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)	13,374,896

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	8,788,922
23	Requirements Sales for Resale (See instruction 4, page 311.)	
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	4,050,611
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	31,825
27	Total Energy Losses	503,538
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	13,374,896

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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	Total Monthly Energy	Monthly Non-Requirments Sales for Resale & Associated Losses	MONTHLY PEAK		
				Megawatts (See Instr. 4)	Day of Month	Hour
	(a)	(b)	(c)	(d)	(e)	(f)
29	January	1,316,830	425,108	1,463	6	0800
30	February	1,196,519	362,758	1,715	6	0800
31	March	1,121,477	326,431	1,514	1	1900
32	April	1,097,028	391,880	1,201	2	0900
33	May	1,120,444	429,119	1,161	22	1700
34	June	1,046,909	370,923	1,253	23	1700
35	July	1,267,533	441,827	1,606	16	1600
36	August	1,074,340	276,884	1,555	5	1700
37	September	958,206	277,911	1,176	17	2000
38	October	957,445	249,042	1,210	28	1900
39	November	1,051,804	224,547	1,524	17	0800
40	December	1,166,361	274,181	1,589	30	1900
41	TOTAL	13,374,896	4,050,611			

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	04/15/2015	End of 2014/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			60		
7	Plant Hours Connected to Load	5981			47		
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	1494579000			2431000		
13	Cost of Plant: Land and Land Rights	0			157277		
14	Structures and Improvements	11377363			744320		
15	Equipment Costs	161756645			13346322		
16	Asset Retirement Costs	351682			0		
17	Total Cost	173485690			14247919		
18	Cost per KW of Installed Capacity (line 17/5) Including	604.4798			230.5489		
19	Production Expenses: Oper, Supv, & Engr	1317291			6110		
20	Fuel	47845299			102159		
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	1440310			11595		
26	Misc Steam (or Nuclear) Power Expenses	453929			3248		
27	Rents	-3453			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	615304			346		
30	Maintenance of Structures	63222			7937		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	1579577			149588		
33	Maintenance of Misc Steam (or Nuclear) Plant	431883			5559		
34	Total Production Expenses	53743362			286542		
35	Expenses per Net KWh	0.0360			0.1179		
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	10197287	0	0	29597	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	4.692	0.000	0.000	3.452	0.000	0.000
41	Average Cost of Fuel per Unit Burned	4.692	0.000	0.000	3.452	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	4.600	0.000	0.000	3.384	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.032	0.000	0.000	0.042	0.000	0.000
44	Average BTU per KWh Net Generation	6959.000	0.000	0.000	12418.000	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) 04/15/2015	Year/Period of Report End of 2014/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
		50			236			164	6
		7188			9236			135	7
		54			222			167	8
		54			222			0	9
		54			222			0	10
		27			145			1	11
		259377000			1464025000			12789000	12
		2289077			1289095			621682	13
		25218744			103016599			3442350	14
		70591160			202194608			59314108	15
		450687			134589			0	16
		98549668			306634891			63378140	17
		1943.7804			1313.7742			380.6495	18
		80395			128048			16829	19
		7509333			21495676			583155	20
		0			0			0	21
		648891			3186923			0	22
		0			0			0	23
		0			0			0	24
		887112			97352			110307	25
		322065			1827430			17285	26
		0			35336			0	27
		0			0			0	28
		201571			376878			2080	29
		175916			619441			219753	30
		1655692			3885558			0	31
		550777			1459490			381808	32
		1608877			1187195			93697	33
		13640629			34299327			1424914	34
		0.0526			0.0234			0.1114	35
Wood	Gas		Coal	Oil		Gas			36
TON	MCF		TON	BBL		MCF			37
433546	3429	0	925391	2411	0	161046	0	0	38
8600000	1020000	0	16970000	5880000	0	1020000	0	0	39
17.281	5.052	0.000	22.869	138.210	0.000	3.621	0.000	0.000	40
17.281	5.052	0.000	22.869	138.210	0.000	3.621	0.000	0.000	41
2.010	4.953	0.000	1.348	23.510	0.000	3.550	0.000	0.000	42
0.029	0.086	0.000	0.015	0.000	0.000	0.046	0.000	0.000	43
14386.000	0.000	0.000	10736.000	0.000	0.000	12844.000	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	04/15/2015	End of 2014/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: *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	836			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	14811000			0		
13	Cost of Plant: Land and Land Rights	185629			0		
14	Structures and Improvements	1204874			0		
15	Equipment Costs	31477546			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	32868049			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	1336.0996			0		
19	Production Expenses: Oper, Supv, & Engr	5047			0		
20	Fuel	606241			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	213474			0		
26	Misc Steam (or Nuclear) Power Expenses	8462			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	690			0		
30	Maintenance of Structures	2933			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	205267			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	37197			0		
34	Total Production Expenses	1079311			0		
35	Expenses per Net KWh	0.0729			0.0000		
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	138582	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	4.375	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	4.375	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	4.289	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.041	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	9544.000	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) 04/15/2015	Year/Period of Report End of 2014/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 Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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

Line No.	Item (a)	(b)			(c)		
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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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	04/15/2015	End of 2014/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	14
7	Plant Hours Connect to Load	8,633	8,432
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	102,775,000	67,033,000
13	Cost of Plant		
14	Land and Land Rights	0	1,081,854
15	Structures and Improvements	11,985,065	978,071
16	Reservoirs, Dams, and Waterways	9,977,635	7,657,054
17	Equipment Costs	12,747,287	5,561,630
18	Roads, Railroads, and Bridges	50,448	490,407
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	34,760,435	15,769,016
21	Cost per KW of Installed Capacity (line 20 / 5)	2,348.6780	1,576.9016
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	4	304
26	Electric Expenses	633,480	551,730
27	Misc Hydraulic Power Generation Expenses	26,950	41,578
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	129
30	Maintenance of Structures	6,736	37,800
31	Maintenance of Reservoirs, Dams, and Waterways	124,756	31,424
32	Maintenance of Electric Plant	40,091	18,670
33	Maintenance of Misc Hydraulic Plant	4,130	8,040
34	Total Production Expenses (total 23 thru 33)	836,147	689,675
35	Expenses per net KWh	0.0081	0.0103

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	04/15/2015	End of 2014/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
16	19	267	6
6,822	5,454	6,804	7
			8
22	15	273	9
22	15	273	10
4	4	11	11
55,630,000	83,872,000	1,194,480,000	12
			13
33,429	3,570,115	12,933,656	14
6,311,993	1,591,055	12,264,580	15
13,594,817	12,716,511	36,763,429	16
17,997,300	3,174,508	48,455,009	17
625,181	0	1,261,219	18
0	0	0	19
38,562,720	21,052,189	111,677,893	20
1,460.7091	1,422.4452	421.4260	21
			22
0	80	98,373	23
0	0	0	24
27	114	4,200	25
606,195	548,151	1,183,873	26
52,246	53,659	142,597	27
0	0	0	28
2,393	113	56,666	29
4,845	31,334	409,546	30
258,893	65,672	61,127	31
57,732	231,759	732,617	32
9,785	14,720	67,073	33
992,116	945,602	2,756,072	34
0.0178	0.0113	0.0023	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	04/15/2015	End of 2014/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)	557	90
7	Plant Hours Connect to Load	5,734	6,554
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	562	88
10	(b) Under the Most Adverse Oper Conditions	562	88
11	Average Number of Employees	11	6
12	Net Generation, Exclusive of Plant Use - Kwh	1,968,070,000	476,442,000
13	Cost of Plant		
14	Land and Land Rights	35,702,496	2,089,177
15	Structures and Improvements	16,773,984	4,473,859
16	Reservoirs, Dams, and Waterways	34,022,788	18,066,342
17	Equipment Costs	106,066,264	12,188,441
18	Roads, Railroads, and Bridges	246,561	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	192,812,093	36,817,819
21	Cost per KW of Installed Capacity (line 20 / 5)	395.2687	525.9688
22	Production Expenses		
23	Operation Supervision and Engineering	154,725	14,827
24	Water for Power	0	0
25	Hydraulic Expenses	64,981	9,721
26	Electric Expenses	1,194,742	721,716
27	Misc Hydraulic Power Generation Expenses	144,079	70,098
28	Rents	0	0
29	Maintenance Supervision and Engineering	49,990	32,239
30	Maintenance of Structures	91,224	33,785
31	Maintenance of Reservoirs, Dams, and Waterways	94,200	267,514
32	Maintenance of Electric Plant	794,552	282,813
33	Maintenance of Misc Hydraulic Plant	58,991	39,651
34	Total Production Expenses (total 23 thru 33)	2,647,484	1,472,364
35	Expenses per net KWh	0.0013	0.0031

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	04/15/2015	End of 2014/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
38	0	0	6
6,618	0	0	7
			8
36	0	0	9
36	0	0	10
5	0	0	11
195,005,000	0	0	12
			13
4,325,371	0	0	14
1,943,376	0	0	15
5,058,551	0	0	16
8,979,462	0	0	17
0	0	0	18
0	0	0	19
20,306,760	0	0	20
634.5863	0.0000	0.0000	21
			22
273	0	0	23
0	0	0	24
14,539	0	0	25
581,162	0	0	26
17,734	0	0	27
802,743	0	0	28
7,514	0	0	29
41,416	0	0	30
346,455	0	0	31
163,609	0	0	32
20,971	0	0	33
1,996,416	0	0	34
0.0102	0.0000	0.0000	35

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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	4,066,000	9,178,262
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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) 04/15/2015	Year/Period of Report End of 2014/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	122,955	216,723	59,676	Nat Gas	465	1
						2
						3
						4
						5
						6
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						46

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	Circuits (h)
1	Group Sum		60.00	60.00		1.00		
2								
3	Group Sum		115.00	115.00		1,535.00		
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	3.00		1
8	Beacon Sub #5	BPA Bell Sub	230.00	230.00	H Type	3.00		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	1.00		1
15	Benewah	Shawnee	230.00	230.00	Steel Pole	59.00		1
16	Noxon Plant	Pine Creek Sub	230.00	230.00	Steel Pole	30.00		1
17	Noxon Plant	Pine Creek Sub	230.00	230.00	H Type	14.00		1
18	Cabinet Gorge Plant	Noxon	230.00	230.00	H Type	19.00		1
19	Benewah Sw. Station	Pine Creek Sub	230.00	230.00	Steel Tower			1
20	Benewah Sw. Station	Pine Creek Sub	230.00	230.00	H Type	43.00		1
21	Divide Creek	Lolo Sub	230.00	230.00	Steel Tower			1
22	Divide Creek	Lolo Sub	230.00	230.00	H Type	43.00		1
23	N. Lewiston	Walla Walla	230.00	230.00	H Type	43.00		1
24	N. Lewiston	Walla Walla	230.00	230.00	Steel Pole	4.00		1
25	N. Lewiston	Shawnee	230.00	230.00	Steel Pole	7.00		1
26	N. Lewiston	Shawnee	230.00	230.00	H Type	27.00		1
27	Walla Walla	Wanapum	230.00	230.00	Alum.			1
28	Walla Walla	Wanapum	230.00	230.00	H Type	15.00		1
29	Walla Walla	Wanapum	230.00	230.00	H Type	63.00		1
30	BPA (Libby)	Noxon Plant	230.00	230.00	Steel Tower	1.00		1
31	BPA/Hot Springs #1	Noxon Plant	230.00	230.00	Steel Tower	1.00		1
32	BPA/Hot Springs #2	Noxon Plant (dead)	230.00	230.00	Steel Tower		2.00	1
33	BPA/Hot Springs #2	Noxon Plant	230.00	230.00	H Type	68.00		1
34	BPA Line	West Side Sub	230.00	230.00	Steel Pole	2.00		2
35	Hatwai	N. Lewiston Sub	230.00	230.00	H Type	7.00		1
36					TOTAL	2,198.00	3.00	34

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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 (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
	136,038	650,395	786,433					1
								2
	10,357,403	143,741,638	154,099,041	354,545	942,967		1,297,512	3
								4
1272 ACSS								5
1272 ACSS	17,912	1,429,560	1,447,472					6
1272 ACSS								7
1272 ACSS	30,323	3,275,357	3,305,680		676		676	8
1272 ACSS								9
1590 ACSS								10
1590 ACSR	1,156,196	41,997,901	43,154,097	506	10,221		10,727	11
1272 ACSS								12
1272 McMAL	456,162	8,873,861	9,330,023	334	33,139		33,473	13
1622 ACSS								14
1590 ACSS	570,207	48,028,103	48,598,310	2,724	23,729		26,453	15
1272 ACSR								16
954 McMAL	1,097,679	18,175,430	19,273,109	5,864	165,128		170,992	17
954 McMAL	184,211	1,639,288	1,823,499	2,566	90,898		93,464	18
954 McMAL								19
954 McMAL	349,690	4,752,406	5,102,096	1,997	17,381		19,378	20
1272 McMAL								21
1272 McMAL	86,228	5,356,470	5,442,698	26,840	7,445		34,285	22
1272 McMAL								23
1272 McMAL	623,984	7,615,581	8,239,565		204		204	24
1272 ACSR								25
1272 ACSR	872,150	10,046,522	10,918,672	274	6,781		7,055	26
1272 McMAL								27
1272 ACSR								28
1272 McMAL	70,781	6,683,479	6,754,260	59,021	2,183		61,204	29
1272 ACSR								30
1272 ACSR		19,521	19,521	1,808			1,808	31
1272 McMAL								32
1272 McMAL	327,878	4,059,400	4,387,278		22,200		22,200	33
1272 ACSR	36,461	594,652	631,113					34
1590 ACSR	113,795	2,600,894	2,714,689	626			626	35
	17,288,149	341,651,083	358,939,232	512,964	1,477,722	88,597	2,079,283	36

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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	Divide Creek	Imnaha	230.00	230.00	H Type	20.00		1
2	Colstrip Plant	Broadview	500.00	500.00				
3								
4								
5								
6								
7								
8								
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21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	2,198.00	3.00	34

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	04/15/2015	End of 2014/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 (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1272 McMAL	205,262	1,325,464	1,530,726	605	2,545		3,150	1
	595,789	30,785,161	31,380,950	55,254	152,225	88,597	296,076	2
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								35
	17,288,149	341,651,083	358,939,232	512,964	1,477,722	88,597	2,079,283	36

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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 From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	No new transmission lines	added in 2014					
2							
3							
4							
5							
6							
7							
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40							
41							
42							
43							
44	TOTAL						

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/Q4

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
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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	04/15/2015	End of 2014/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 Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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 Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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	Lewiston Mill Rd	Distr. Unattended	115.00	13.20	
37	Lolo	Tran & Dist Unattnd	230.00	115.00	13.80
38	Moscow	Distr. Unattended	115.00	13.80	
39	Moscow 230Kv	Tran & Dist Unattnd	230.00	115.00	13.80
40	North Moscow	Distr. Unattended	115.00	13.80	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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
12	1		Two Stage Fan	1	20	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
18	1		Two Stage Fan	1	30	36
262	3		Frcd Oil/Air/Two Stg	1	270	37
24	2		FrOil/Air/2Stg Fan	2	40	38
162	2		Frcd Air Fan & Caps	48	270	39
12	1		Two Stage Fan	1	20	40

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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 230kV	Tran & Dist Unattnd	230.00	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				

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	04/15/2015	End of 2014/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.
258	2		Frcd Air Fan & Caps	48	260	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

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	04/15/2015	End of 2014/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	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	2 subs	Trans. Unattended			
14	48 subs	Distr. Unattended			
15	5 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					
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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	04/15/2015	End of 2014/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
150						13
668						14
1418						15
430						16
435						17
5						18
213						19
6145						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						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	04/15/2015	End of 2014/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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

Line No.	Description of the 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**			
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20	**Non-power Goods or Services Provided for Affiliate**			
21	Corporate Service Support	Salix Inc.	146000	794,279
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