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

Form 2 Approved
OMB No.1902-0028
(Expires 10/31/2014)

Form 3-Q Approved
OMB No.1902-0205
(Expires 05/31/2014)

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

These reports are mandatory under the Natural Gas Act, Sections 10(a), and 16 and 18 CFR Parts 260.1 and 260.300. Failure to report may result in criminal fines, civil penalties, and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of a confidential nature.

Exact Legal Name of Respondent (Company)	Year/Period of Report
Avista Corporation	**End of** 2012/Q4

FERC FORM No. 2/3Q (02-04)

QUARTERLY/ANNUAL REPORT OF MAJOR NATURAL GAS COMPANIES

IDENTIFICATION

01 Exact Legal Name of Respondent	Year/Period of Report
Avista Corporation	End of 2012/Q4

03 Previous Name and Date of Change (If name changed during year)

04 Address of Principal Office at End of Year (Street, City, State, Zip Code)
1411 East Mission Avenue, Spokane, WA 99207

05 Name of Contact Person	06 Title of Contact Person
Christy Burmeister-Smith	VP, Controller, Prin. Acctg Officer

07 Address of Contact Person (Street, City, State, Zip Code)
1411 East Mission Avenue, Spokane, WA 99207

08 Telephone of Contact Person, Including Area Code	This Report Is:	10 Date of Report (Mo, Da, Yr)
509-495-4256	(1) [X] An Original (2) [ ] A Resubmission	04/12/2013

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

11 Name	12 Title
Christy Burmeister-Smith	VP, Controller, Prin. Acctg Officer
13 Signature Christy Burmeister-Smith	14 Date Signed 04/12/2013

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

Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

List of Schedules (Natural Gas Company)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Date Revised (c)	Remarks (d)
	GENERAL CORPORATE INFORMATION AND FINANCIAL STATEMENTS			
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19	General Description of Construction Overhead Procedure	218		
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22	Investments	222-223		
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25	Extraordinary Property Losses	230		N/A
26	Unrecovered Plant and Regulatory Study Costs	230		N/A
27	Other Regulatory Assets	232		
28	Miscellaneous Deferred Debits	233		
29	Accumulated Deferred Income Taxes	234-235		
	BALANCE SHEET SUPPORTING SCHEDULES (Liabilities and Other Credits)			
30	Capital Stock	250-251		
31	Capital Stock Subscribed, Capital Stock Liability for Conversion, Premium on Capital Stock, and Installments Received on Capital Stock	252		N/A
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Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

List of Schedules (Natural Gas Company) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Date Revised (c)	Remarks (d)
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49	Revenues from Transportation of Gas of Others Through Transmission Facilities	304-305		N/A
50	Revenues from Storage Gas of Others	306-307		N/A
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53	Gas Operation and Maintenance Expenses	317-325		
54	Exchange and Imbalance Transactions	328		N/A
55	Gas Used in Utility Operations	331		
56	Transmission and Compression of Gas by Others	332		N/A
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58	Miscellaneous General Expenses-Gas	335		
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60	Particulars Concerning Certain Income Deduction and Interest Charges Accounts	340		
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64	Charges for Outside Professional and Other Consultative Services	357		
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67	Gas Storage Projects	512-513		
68	Transmission Lines	514		N/A
69	Transmission System Peak Deliveries	518		N/A
70	Auxiliary Peaking Facilities	519		
71	Gas Account-Natural Gas	520		
72	Shipper Supplied Gas for the Current Quarter	521		N/A
73	System Map	522		N/A
74	Footnote Reference	551		
75	Footnote Text	552		
76	Stockholder's Reports (check appropriate box)			
	[X] Four copies will be submitted [ ] No annual report to stockholders is prepared			

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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.

Christy Burmeister-Smith, Vice President and Controller
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 of utility and other services furnished by respondent during the year in each State in which the respondent operated.

Electric service in the states of Washington, Idaho and Montana

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

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

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

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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.
4. In column (b) designate type of control of the respondent as "D" for direct, an "I" for indirect, or a "J" for joint control.

DEFINITIONS

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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 that 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)	Type of Control (b)	Kind of Business (c)	Percent Voting Stock Owned (d)	Footnote Reference (e)
1	Avista Capital, Inc.	D	Parent company to the Company's subsidiaries.	100	Not used
2	Ecova, Inc.	I	Provides utility bill processing services	79	Not used
3					
4	Avista Development, Inc.	I	Maintains investment portfolio incl. real estate	100	Not used
5	Avista Energy, Inc.	I	Inactive	100	Not used
6	Pentzer Corporation	I	Parent of Bay Area Mfg and Pentzer Venture Hldngs	100	Not used
7	Pentzer Venture Holdings	I	Inactive	100	Not used
8	Bay Area Manufacturing	I	Holding co. of AM&D dba MetalFX	100	Not used
9	Advanced Manufacturing & Development	I	Custom mfg of electronic enclosures	83	Not used
10	dba MetalFX	I			Not used
11	Spokane Energy, LLC	D	Owns an electric capacity contract.	100	Not used
12	Avista Capital II	D	Affiliated business trust issued pref trust sec.	100	Not used
13	Avista Northwest Resources, LLC	I	Owns an interest in a venture fund investment	100	Not used
14	Steam Plant Square, LLC	I	Commercial office and retail leasing	85	Not used
15	Courtyard Office Center, LLC	I	Commercial office and retail leasing	100	Not used
16	Steam Plant Brew Pub, LLC	I	Restaurant operations	85	Not used
17		I			
18		I			
19		I			
20		I			
21					
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Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

Security Holders and Voting Powers

1. Give the names and addresses of the 10 security holders of the respondent who, at the date of the latest closing of the stock book or compilation of list of stockholders of the respondent, prior to the end of the year, had the highest voting powers in the respondent, and state the number of votes that each could cast on that date if a meeting were held. If any such holder held in trust, give in a footnote the known particulars of the trust (whether voting trust, etc.), duration of trust, and principal holders of beneficiary interests in the trust. If the company did not close the stock book or did not compile a list of stockholders within one year prior to the end of the year, or if since it compiled the previous list of stockholders, some other class of security has become vested with voting rights, then show such 10 security holders as of the close of the year. Arrange the names of the security holders in the order of voting power, commencing with the highest. Show in column (a) the titles of officers and directors included in such list of 10 security holders.
2. If any security other than stock carries voting rights, explain in a supplemental statement how such security became vested with voting rights and give other important details concerning the voting rights of such security. State whether voting rights are actual or contingent; if contingent, describe the contingency.
3. If any class or issue of security has any special privileges in the election of directors, trustees or managers, or in the determination of corporate action by any method, explain briefly in a footnote.
4. Furnish details concerning any options, warrants, or rights outstanding at the end of the year for others to purchase securities of the respondent or any securities or other assets owned by the respondent, including prices, expiration dates, and other material information relating to exercise of the options, warrants, or rights. Specify the amount of such securities or assets any officer, director, associated company, or any of the 10 largest security holders is entitled to purchase. This instruction is inapplicable to convertible securities or to any securities substantially all of which are outstanding in the hands of the general public where the options, warrants,

1. Give date of the latest closing of the stock book prior to end of year, and, in a footnote, state the purpose of such closing:	2. State the total number of votes cast at the latest general meeting prior to the end of year for election of directors of the respondent and number of such votes cast by proxy.	3. Give the date and place of such meeting:
11/29/2012	Total: 52774389 By Proxy: 52774389	May 10, 2012 Spokane, WA

Line No.	Name (Title) and Address of Security Holder (a)	VOTING SECURITIES 4. Number of votes as of (date): 11/29/2012 Total Votes (b)	Common Stock (c)	Preferred Stock (d)	Other (e)
5	TOTAL votes of all voting securities	58,627,915	58,627,915		
6	TOTAL number of security holders	10,629	10,629		
7	TOTAL votes of security holders listed below				
8	GARY ELY, LIBERTY LAKE, WA	141,984	141,984		
9	DBH PROPERTIES LP, COEUR D'ALENE, ID	77,646	77,646		
10	GARY GAIL ELY, LIBERTY LAKE, WA	65,218	65,218		
11	JACK W GUSTAVEL, COEUR D'ALENE, ID	40,740	40,740		
12	MARK T THIES, SPOKANE, WA	24,163	24,163		
13	MARIAN M DURKIN, SPOKANE, WA	23,986	23,986		
14	KAREN S FELTES, SPOKANE, WA	20,345	20,345		
15	FREDERICK W SCHOTT TR, SANTA MONICA, CA	19,498	19,498		
16	JOHN F KELLY, CORAL GABLES, FL	19,342	19,342		
17	THOMAS A LOWE & KATHLEEN B LOWE, TR UA, SATELLITE BEACH, FL	17,360	17,360		
18					
19					
20					

Name of Respondent	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report 2012/Q4

FOOTNOTE DATA

Schedule Page: 107 Line No.: 1 Column: 1

To pay the December 14, 2012, dividend.

Name of Respondent	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report 2012/Q4

Important Changes During the Quarter/Year

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

1. Changes in and important additions to franchise rights: Describe the actual consideration and state from whom the franchise rights were acquired. If the franchise rights were acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Briefly describe the property, and the related transactions, and cite Commission authorization, if any was required. Give date journal entries called for by Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other conditions. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and cite Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service.
Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred or assumed by respondent as guarantor for the performance by another of any agreement or obligation, including ordinary commercial paper maturing on demand or not later than one year after date of issue: State on behalf of whom the obligation was assumed and amount of the obligation. Cite Commission authorization if any was required.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. Estimated increase or decrease in annual revenues caused by important rate changes: State effective date and approximate amount of increase or decrease for each revenue classification. State the number of customers affected.
12. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
13. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

1. None
2. None
3. None
4. None
5. None
6. Avista Corp. has a committed line of credit with various financial institutions in the total amount of $400.0 million with an expiration date of February 2017. The committed line of credit is secured by non-transferable First Mortgage Bonds of the Company issued to the agent bank that would only become due and payable in the event, and then only to the extent, that the Company defaults on its obligations under the committed line of credit.

Balances outstanding under the Company's revolving committed line of credit were as follows as of December 31, 2012 and December 31, 2011 (dollars in thousands):

	December 31, 2012	December 31, 2011
Balance outstanding at end of period	$52,000	$61,000
Letters of credit outstanding at end of period	$35,885	$29,030

In June 2012, Avista Corp. entered into a bond purchase agreement with certain institutional investors in the private placement market for the purpose of issuing $80.0 million of 4.23 percent First Mortgage Bonds due in 2047. The new First Mortgage Bonds were issued under and in accordance with the Mortgage and Deed of Trust, dated as of June 1, 1939, from the Company to Citibank, N.A., trustee, as amended and supplemented by various supplemental indentures and other instruments. The issuance of the bonds occurred at closing in November 2012. 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. On May 10, 2012, the shareholders of Avista Corp. approved an amendment of the Company's Restated Articles of Incorporation and Bylaws to reduce certain shareholder approval requirements to reduce the approval standards for shareholder voting to a "Majority of Votes Cast", where permissible under Washington law, and otherwise to be the lowest threshold permitted by Washington law.

8. Average annual wage increases were 2.4% for non-exempt employees effective February 27, 2012. Average annual wage increases were 2.7% for exempt employees effective February 27, 2012. Officers received average increases of 3.5% effective February 27, 2012. Certain bargaining unit employees received increases of 3.0% effective March 26, 2012.

9. Reference is made to Note 18 of the Notes to Financial Statements.

10. None

11. Reference is made to Note 20 of the Notes to Financial Statements.

12. Effective June 1, 2012, Avista Corp. appointed Don Kopczynski as Vice President of Operations and Jason Thackston as Vice President of Customer Solutions. Mr. Kopczynski was previously Vice President of Customer Solutions and Mr. Thackston was previously Vice President of Energy Delivery.

13. Proprietary capital is not less than 30 percent.

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Comparative Balance Sheet (Assets and Other Debits)

Line No.	Title of Account (a)	Reference Page Number (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	4,044,184,930	3,876,924,839
3	Construction Work in Progress (107)	200-201	139,513,892	78,182,230
4	TOTAL Utility Plant (Total of lines 2 and 3)	200-201	4,183,698,822	3,955,107,069
5	(Less) Accum. Provision for Depr., Amort., Depl. (108, 111, 115)		1,408,153,972	1,333,212,160
6	Net Utility Plant (Total of line 4 less 5)		2,775,544,850	2,621,894,909
7	Nuclear Fuel (120.1 thru 120.4, and 120.6)		0	0
8	(Less) Accum. Provision for Amort., of Nuclear Fuel Assemblies (120.5)		0	0
9	Nuclear Fuel (Total of line 7 less 8)		0	0
10	Net Utility Plant (Total of lines 6 and 9)		2,775,544,850	2,621,894,909
11	Utility Plant Adjustments (116)	122	0	0
12	Gas Stored-Base Gas (117.1)	220	6,992,076	6,992,076
13	System Balancing Gas (117.2)	220	0	0
14	Gas Stored in Reservoirs and Pipelines-Noncurrent (117.3)	220	0	0
15	Gas Owed to System Gas (117.4)	220	0	0
16	**OTHER PROPERTY AND INVESTMENTS**			
17	Nonutility Property (121)		5,536,702	6,021,869
18	(Less) Accum. Provision for Depreciation and Amortization (122)		921,820	915,043
19	Investments in Associated Companies (123)	222-223	12,047,000	12,047,000
20	Investments in Subsidiary Companies (123.1)	224-225	118,714,423	71,971,368
21	(For Cost of Account 123.1 See Footnote Page 224, line 40)			
22	Noncurrent Portion of Allowances		0	0
23	Other Investments (124)	222-223	16,439,055	18,889,385
24	Sinking Funds (125)		0	0
25	Depreciation Fund (126)		0	0
26	Amortization Fund - Federal (127)		0	0
27	Other Special Funds (128)		9,154,874	13,288,292
28	Long-Term Portion of Derivative Assets (175)		1,092,593	184,929
29	Long-Term Portion of Derivative Assets - Hedges (176)		0	0
30	TOTAL Other Property and Investments (Total of lines 17-20, 22-29)		162,062,827	121,487,800
31	**CURRENT AND ACCRUED ASSETS**			
32	Cash (131)		2,624,516	945,496
33	Special Deposits (132-134)		2,716,333	22,215,906
34	Working Funds (135)		799,065	861,010
35	Temporary Cash Investments (136)	222-223	251,390	60,913
36	Notes Receivable (141)		234,901	283,666
37	Customer Accounts Receivable (142)		159,703,153	173,557,636
38	Other Accounts Receivable (143)		5,188,679	7,943,467
39	(Less) Accum. Provision for Uncollectible Accounts - Credit (144)		4,653,167	4,498,489
40	Notes Receivable from Associated Companies (145)		314,682	0
41	Accounts Receivable from Associated Companies (146)		700,835	29,252
42	Fuel Stock (151)		4,120,767	4,248,389
43	Fuel Stock Expenses Undistributed (152)		0	0

Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

Comparative Balance Sheet (Assets and Other Debits)(continued)

Line No.	Title of Account (a)	Reference Page Number (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
44	Residuals (Elec) and Extracted Products (Gas) (153)		0	0
45	Plant Materials and Operating Supplies (154)		23,875,397	21,746,205
46	Merchandise (155)		0	0
47	Other Materials and Supplies (156)		0	0
48	Nuclear Materials Held for Sale (157)		0	0
49	Allowances (158.1 and 158.2)		0	0
50	(Less) Noncurrent Portion of Allowances		0	0
51	Stores Expense Undistributed (163)		0	0
52	Gas Stored Underground-Current (164.1)	220	17,276,287	23,609,470
53	Liquefied Natural Gas Stored and Held for Processing (164.2 thru 164.3)	220	0	0
54	Prepayments (165)	230	16,090,480	16,554,560
55	Advances for Gas (166 thru 167)		0	0
56	Interest and Dividends Receivable (171)		31,981	85,059
57	Rents Receivable (172)		830,718	1,568,627
58	Accrued Utility Revenues (173)		0	0
59	Miscellaneous Current and Accrued Assets (174)		429,169	254,324
60	Derivative Instrument Assets (175)		5,231,375	1,323,663
61	(Less) Long-Term Portion of Derivative Instrument Assets (175)		1,092,593	184,929
62	Derivative Instrument Assets - Hedges (176)		7,265,426	32,408
63	(Less) Long-Term Portion of Derivative Instrument Assests - Hedges (176)		0	0
64	TOTAL Current and Accrued Assets (Total of lines 32 thru 63)		241,939,394	270,636,633
65	**DEFERRED DEBITS**			
66	Unamortized Debt Expense (181)		13,532,890	14,332,877
67	Extraordinary Property Losses (182.1)	230	0	0
68	Unrecovered Plant and Regulatory Study Costs (182.2)	230	0	0
69	Other Regulatory Assets (182.3)	232	559,831,454	524,250,326
70	Preliminary Survey and Investigation Charges (Electric)(183)		3,894,551	4,180,937
71	Preliminary Survey and Investigation Charges (Gas)(183.1 and 183.2)		0	0
72	Clearing Accounts (184)		0	0
73	Temporary Facilities (185)		0	0
74	Miscellaneous Deferred Debits (186)	233	15,701,369	34,001,379
75	Deferred Losses from Disposition of Utility Plant (187)		0	0
76	Research, Development, and Demonstration Expend. (188)		0	0
77	Unamortized Loss on Reacquired Debt (189)		21,635,414	23,830,734
78	Accumulated Deferred Income Taxes (190)	234-235	148,425,469	153,408,420
79	Unrecovered Purchased Gas Costs (191)		(6,916,577)	(12,140,283)
80	TOTAL Deferred Debits (Total of lines 66 thru 79)		756,104,570	741,864,390
81	TOTAL Assets and Other Debits (Total of lines 10-15,30,64,and 80)		3,942,643,717	3,762,875,808

Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

Comparative Balance Sheet (Liabilities and Other Credits)

Line No.	Title of Account (a)	Reference Page Number (b)	Current Year End of Quarter/Year Balance	Prior Year End Balance 12/31 (d)
1	**PROPRIETARY CAPITAL**			
2	Common Stock Issued (201)	250-251	863,316,222	832,413,930
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)	252	0	0
5	Stock Liability for Conversion (203, 206)	252	0	0
6	Premium on Capital Stock (207)	252	0	0
7	Other Paid-In Capital (208-211)	253	10,942,942	11,686,949
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)	254	(14,977,565)	(11,086,811)
11	Retained Earnings (215, 215.1, 216)	118-119	377,687,824	364,536,285
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	(747,337)	(28,386,302)
13	(Less) Reacquired Capital Stock (217)	250-251	0	0
14	Accumulated Other Comprehensive Income (219)	117	(6,700,160)	(5,636,826)
15	TOTAL Proprietary Capital (Total of lines 2 thru 14)		1,259,477,056	1,185,700,847
16	**LONG TERM DEBT**			
17	Bonds (221)	256-257	1,336,700,000	1,257,171,208
18	(Less) Reacquired Bonds (222)	256-257	83,700,000	83,700,000
19	Advances from Associated Companies (223)	256-257	51,547,000	51,547,000
20	Other Long-Term Debt (224)	256-257	0	0
21	Unamortized Premium on Long-Term Debt (225)	258-259	204,316	213,200
22	(Less) Unamortized Discount on Long-Term Debt-Dr (226)	258-259	1,656,685	1,838,814
23	(Less) Current Portion of Long-Term Debt		0	0
24	TOTAL Long-Term Debt (Total of lines 17 thru 23)		1,303,094,631	1,223,392,594
25	**OTHER NONCURRENT LIABILITIES**			
26	Obligations Under Capital Leases-Noncurrent (227)		4,491,191	4,749,777
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		700,447	3,235,000
29	Accumulated Provision for Pensions and Benefits (228.3)		283,984,764	246,176,609
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		0	0

Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

Comparative Balance Sheet (Liabilities and Other Credits)(continued)

Line No.	Title of Account (a)	Reference Page Number (b)	Current Year End of Quarter/Year Balance	Prior Year End Balance 12/31 (d)
32	Long-Term Portion of Derivative Instrument Liabilities		26,310,290	40,530,269
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	2,641,867
34	Asset Retirement Obligations (230)		3,167,936	3,512,818
35	TOTAL Other Noncurrent Liabilities (Total of lines 26 thru 34)		318,654,628	300,846,340
36	**CURRENT AND ACCRUED LIABILITIES**			
37	Current Portion of Long-Term Debt		0	0
38	Notes Payable (231)		52,000,000	61,000,000
39	Accounts Payable (232)		116,147,642	98,160,779
40	Notes Payable to Associated Companies (233)		598	1,866,383
41	Accounts Payable to Associated Companies (234)		709,623	709,883
42	Customer Deposits (235)		3,323,152	8,868,640
43	Taxes Accrued (236)	262-263	22,309,642	8,292,344
44	Interest Accrued (237)		12,038,698	11,797,709
45	Dividends Declared (238)		0	0
46	Matured Long-Term Debt (239)		0	0
47	Matured Interest (240)		0	0
48	Tax Collections Payable (241)		120,427	104,100
49	Miscellaneous Current and Accrued Liabilities (242)	268	61,331,657	55,333,088
50	Obligations Under Capital Leases-Current (243)		258,586	224,884
51	Derivative Instrument Liabilities (244)		55,825,491	111,353,644
52	(Less) Long-Term Portion of Derivative Instrument Liabilities		26,310,290	40,530,269
53	Derivative Instrument Liabilities - Hedges (245)		1,433,160	18,895,143
54	(Less) Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	2,641,867
55	TOTAL Current and Accrued Liabilities (Total of lines 37 thru 54)		299,188,386	333,434,461
56	**DEFERRED CREDITS**			
57	Customer Advances for Construction (252)		947,342	947,213
58	Accumulated Deferred Investment Tax Credits (255)		12,613,058	10,400,886
59	Deferred Gains from Disposition of Utility Plant (256)		0	0
60	Other Deferred Credits (253)	269	26,169,966	26,584,147
61	Other Regulatory Liabilities (254)	278	55,244,962	20,939,852
62	Unamortized Gain on Reacquired Debt (257)	260	2,355,118	2,484,655
63	Accumulated Deferred Income Taxes - Accelerated Amortization (281)		0	0
64	Accumulated Deferred Income Taxes - Other Property (282)		419,216,613	398,500,293
65	Accumulated Deferred Income Taxes - Other (283)		245,681,957	259,644,520
66	TOTAL Deferred Credits (Total of lines 57 thru 65)		762,229,016	719,501,566
67	TOTAL Liabilities and Other Credits (Total of lines 15,24,35,55,and 66)		3,942,643,717	3,762,875,808

Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

Statement of Income

Quarterly
1. Enter in column (d) the balance for the reporting quarter and in column (e) the balance for the same three month period for the prior year.
2. Report in column (f) the quarter to date amounts for electric utility function; in column (h) the quarter to date amounts for gas utility, and in (j) the quarter to date amounts for other utility function for the current year quarter.
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 (k) the quarter to date amounts for other utility function for the prior year quarter.
4. 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.
8. Report data for lines 8, 10 and 11 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1 and 407.2.
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 mehods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

Line No.	Title of Account (a)	Reference Page Number (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current Three Months Ended Quarterly Only No Fourth Quarter (e)	Prior Three Months Ended Quarterly Only No Fourth Quarter (f)
1	UTILITY OPERATING INCOME					
2	Gas Operating Revenues (400)	300-301	1,494,227,540	1,617,162,384	0	0
3	Operating Expenses					
4	Operation Expenses (401)	317-325	1,051,630,004	1,169,781,694	0	0
5	Maintenance Expenses (402)	317-325	61,377,568	57,411,515	0	0
6	Depreciation Expense (403)	336-338	102,188,312	96,771,421	0	0
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-338	0	0	0	0
8	Amortization and Depletion of Utility Plant (404-405)	336-338	12,353,382	11,307,561	0	0
9	Amortization of Utility Plant Acu. Adjustment (406)	336-338	99,047	99,047	0	0
10	Amort. of Prop. Losses, Unrecovered Plant and Reg. Study Costs (407.1)		0	0	0	0
11	Amortization of Conversion Expenses (407.2)		0	0	0	0
12	Regulatory Debits (407.3)		5,612,331	3,529,991	0	0
13	(Less) Regulatory Credits (407.4)		24,170,474	19,872,716	0	0
14	Taxes Other than Income Taxes (408.1)	262-263	83,263,801	83,348,911	0	0
15	Income Taxes-Federal (409.1)	262-263	14,435,558	23,554,951	0	0
16	Income Taxes-Other (409.1)	262-263	379,911	1,264,963	0	0
17	Provision of Deferred Income Taxes (410.1)	234-235	35,782,466	29,793,186	0	0
18	(Less) Provision for Deferred Income Taxes-Credit (411.1)	234-235	4,224,555	2,475,028	0	0
19	Investment Tax Credit Adjustment-Net (411.4)		2,073,106	2,458,952	0	0
20	(Less) Gains from Disposition of Utility Plant (411.6)		0	0	0	0
21	Losses from Disposition of Utility Plant (411.7)		0	0	0	0
22	(Less) Gains from Disposition of Allowances (411.8)		0	0	0	0
23	Losses from Disposition of Allowances (411.9)		0	0	0	0
24	Accretion Expense (411.10)		0	0	0	0
25	TOTAL Utility Operating Expenses (Total of lines 4 thru 24)		1,340,800,457	1,456,974,448	0	0
26	Net Utility Operating Income (Total of lines 2 less 25) (Carry forward to page 116, line 27)		153,427,083	160,187,936	0	0

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Statement of Income

Line No.	Elec. Utility Current Year to Date (in dollars) (g)	Elec. Utility Previous Year to Date (in dollars) (h)	Gas Utility Current Year to Date (in dollars) (i)	Gas Utility Previous Year to Date (in dollars) (j)	Other Utility Current Year to Date (in dollars) (k)	Other Utility Previous Year to Date (in dollars) (l)
1						
2	1,017,916,105	1,053,850,680	476,311,435	563,311,704	0	0
3						
4	664,363,922	702,686,156	387,266,082	467,095,538	0	0
5	50,481,432	47,524,279	10,896,136	9,887,236	0	0
6	83,017,204	78,744,936	19,171,108	18,026,485	0	0
7	0	0	0	0	0	0
8	9,725,903	9,015,875	2,627,479	2,291,686	0	0
9	99,047	99,047	0	0	0	0
10	0	0	0	0	0	0
11	0	0	0	0	0	0
12	4,618,160	3,366,279	994,171	163,712	0	0
13	22,537,730	17,238,278	1,632,744	2,634,438	0	0
14	62,217,029	61,363,417	21,046,772	21,985,494	0	0
15	16,824,429	23,647,758	(2,388,871)	(92,807)	0	0
16	432,992	922,947	(53,081)	342,016	0	0
17	24,012,637	17,702,120	11,769,829	12,091,066	0	0
18	4,120,508	2,793,831	104,047	(318,803)	0	0
19	2,115,166	2,502,656	(42,060)	(43,704)	0	0
20	0	0	0	0	0	0
21	0	0	0	0	0	0
22	0	0	0	0	0	0
23	0	0	0	0	0	0
24	0	0	0	0	0	0
25	891,249,683	927,543,361	449,550,774	529,431,087	0	0
26	126,666,422	126,307,319	26,760,661	33,880,617	0	0

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Statement of Income(continued)

Line No.	Title of Account (a)	Reference Page Number (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current Three Months Ended Quarterly Only No Fourth Quarter (e)	Prior Three Months Ended Quarterly Only No Fourth Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		153,427,083	160,187,936	0	0
28	OTHER INCOME AND DEDUCTIONS					
29	Other Income					
30	Nonutility Operating Income					
31	Revenues form Merchandising, Jobbing and Contract Work (415)		0	0	0	0
32	(Less) Costs and Expense of Merchandising, Job & Contract Work (416)		0	0	0	0
33	Revenues from Nonutility Operations (417)		(236)	(21,355)	0	0
34	(Less) Expenses of Nonutility Operations (417.1)		8,415,859	6,836,563	0	0
35	Nonoperating Rental Income (418)		(2,749)	(2,731)	0	0
36	Equity in Earnings of Subsidiary Companies (418.1)	119	(1,206,861)	9,971,326	0	0
37	Interest and Dividend Income (419)		1,864,293	1,293,357	0	0
38	Allowance for Other Funds Used During Construction (419.1)		4,054,947	2,224,987	0	0
39	Miscellaneous Nonoperating Income (421)		0	0	0	0
40	Gain on Disposition of Property (421.1)		0	31,120	0	0
41	TOTAL Other Income (Total of lines 31 thru 40)		(3,706,465)	6,660,141	0	0
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		0	0	0	0
44	Miscellaneous Amortization (425)		0	304,717	0	0
45	Donations (426.1)	340	2,272,123	2,143,177	0	0
46	Life Insurance (426.2)		2,533,552	2,253,671	0	0
47	Penalties (426.3)		15,251	281,762	0	0
48	Expenditures for Certain Civic, Political and Related Activities (426.4)		1,414,338	1,186,022	0	0
49	Other Deductions (426.5)		1,815,326	407,223	0	0
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)	340	8,050,590	6,576,572	0	0
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other than Income Taxes (408.2)	262-263	145,213	(2,275)	0	0
53	Income Taxes-Federal (409.2)	262-263	106,965	(962,923)	0	0
54	Income Taxes-Other (409.2)	262-263	(1,231,456)	(349,700)	0	0
55	Provision for Deferred Income Taxes (410.2)	234-235	(520,718)	40,666	0	0
56	(Less) Provision for Deferred Income Taxes-Credit (411.2)	234-235	5,190,742	4,710,550	0	0
57	Investment Tax Credit Adjustments-Net (411.5)		0	0	0	0
58	(Less) Investment Tax Credits (420)		0	0	0	0
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		(6,690,738)	(5,984,782)	0	0
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		(5,066,317)	6,068,351	0	0
61	INTEREST CHARGES					
62	Interest on Long-Term Debt (427)		66,281,624	61,400,721	0	0
63	Amortization of Debt Disc. and Expense (428)	258-259	447,351	604,805	0	0
64	Amortization of Loss on Reacquired Debt (428.1)		3,364,150	4,021,281	0	0
65	(Less) Amortization of Premium on Debt-Credit (429)	258-259	8,883	8,883	0	0
66	(Less) Amortization of Gain on Reacquired Debt-Credit (429.1)		0	0	0	0
67	Interest on Debt to Associated Companies (430)	340	885,123	(26,307)	0	0
68	Other Interest Expense (431)	340	2,582,407	2,983,099	0	0
69	(Less) Allowance for Borrowed Funds Used During Construction-Credit (432)		2,401,072	2,942,302	0	0
70	Net Interest Charges (Total of lines 62 thru 69)		70,150,700	66,032,414	0	0
71	Income Before Extraordinary Items (Total of lines 27,60 and 70)		78,210,066	100,223,873	0	0
72	EXTRAORDINARY ITEMS					
73	Extraordinary Income (434)		0	0	0	0
74	(Less) Extraordinary Deductions (435)		0	0	0	0
75	Net Extraordinary Items (Total of line 73 less line 74)		0	0	0	0
76	Income Taxes-Federal and Other (409.3)	262-263	0	0	0	0
77	Extraordinary Items after Taxes (Total of line 75 less line 76)		0	0	0	0
78	Net Income (Total of lines 71 and 77)		78,210,066	100,223,873	0	0

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Statement of Accumulated Comprehensive Income and Hedging Activities

1. Report in columns (b) (c) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.

2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.

3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.

Line No.	Item (a)	Unrealized Gains and Losses on available-for-sale securities (b)	Minimum Pension liability Adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year		(4,325,953)		
2	Preceding Quarter/Year to Date Reclassifications from Account 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value	134,046	(1,444,919)		
4	Total (lines 2 and 3)	134,046	(1,444,919)		
5	Balance of Account 219 at End of Preceding Quarter/Year	134,046	(5,770,872)		
6	Balance of Account 219 at Beginning of Current Year	134,046	(5,770,872)		
7	Current Quarter/Year to Date Reclassifications from Account 219 to Net Income	(290,263)			
8	Current Quarter/Year to Date Changes in Fair Value	323,478	(1,096,549)		
9	Total (lines 7 and 8)	33,215	(1,096,549)		
10	Balance of Account 219 at End of Current Quarter/Year	167,261	(6,867,421)		

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Statement of Accumulated Comprehensive Income and Hedging Activities(continued)

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges (Insert Category) (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 116, Line 78) (i)	Total Comprehensive Income (j)
1			(4,325,953)	[redacted]	
2					
3			(1,310,873)		
4			(1,310,873)	100,223,872	98,912,999
5			(5,636,826)	[redacted]	
6			(5,636,826)		
7			(290,263)		
8			(773,071)		
9			(1,063,334)	78,210,066	77,146,732
10			(6,700,160)	[redacted]	

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Statement of Retained Earnings

1. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
2. 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).
3. State the purpose and amount for each reservation or appropriation of retained earnings.
4. 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.
5. Show dividends for each class and series of capital stock.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter Year to Date Balance (c)	Previous Quarter Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS			
1	Balance-Beginning of Period		362,988,164	325,313,182
2	Changes (Identify by prescribed retained earnings accounts)			
3	Adjustments to Retained Earnings (Account 439)			
4	TOTAL Credits to Retained Earnings (Account 439) (footnote details)			10,509,950
5	TOTAL Debits to Retained Earnings (Account 439) (footnote details)			
6	Balance Transferred from Income (Acct 433 less Acct 418.1)		79,416,927	90,252,547
7	Appropriations of Retained Earnings (Account 436)			
8	TOTAL Appropriations of Retained Earnings (Account 436) (footnote details)			
9	Dividends Declared-Preferred Stock (Account 437)			
10	TOTAL Dividends Declared-Preferred Stock (Account 437) (footnote details)			
11	Dividends Declared-Common Stock (Account 438)			
12	TOTAL Dividends Declared-Common Stock (Account 438) (footnote details)		68,552,375	63,736,956
13	Transfers from Account 216.1, Unappropriated Undistributed Subsidiary Earnings		2,286,987	649,441
14	Balance-End of Period (Total of lines 1, 4, 5, 6, 8, 10, 12, and 13)		376,139,703	362,988,164
15	APPROPRIATED RETAINED EARNINGS (Account 215)			
16	TOTAL Appropriated Retained Earnings (Account 215) (footnote details)		1,548,121	1,548,121
17	APPROPRIATED RETAINED EARNINGS-AMORTIZATION RESERVE, FEDERAL (Account			
18	TOTAL Appropriated Retained Earnings-Amortization Reserve, Federal (Account			
19	TOTAL Appropriated Retained Earnings (Accounts 215, 215.1) (Total of lines		1,548,121	1,548,121
20	TOTAL Retained Earnings (Accounts 215, 215.1, 216) (Total of lines 14 and 1		377,687,824	364,536,285
21	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account 216.1)			
	Report only on an Annual Basis no Quarterly			
22	Balance-Beginning of Year (Debit or Credit)		(28,386,302)	(24,343,433)
23	Equity in Earnings for Year (Credit) (Account 418.1)		(1,206,861)	9,971,326
24	(Less) Dividends Received (Debit)			
25	Other Changes (Explain)		28,845,826	(14,014,195)
26	Balance-End of Year		(747,337)	(28,386,302)

Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/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 25) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instructions for explanation of codes) (a)	Current Year to Date Quarter/Year	Previous Year to Date Quarter/Year
1	Net Cash Flow from Operating Activities		
2	Net Income (Line 78(c) on page 116)	78,210,066	100,223,872
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	112,091,663	105,727,999
5	Amortization of deferred power and gas costs, debt expense and exchange power	12,954,915	28,936,761
6	Deferred Income Taxes (Net)	19,589,845	21,115,803
7	Investment Tax Credit Adjustments (Net)	2,212,172	2,558,524
8	Net (Increase) Decrease in Receivables	12,838,942	3,428,347
9	Net (Increase) Decrease in Inventory	4,331,613	(2,737,133)
10	Net (Increase) Decrease in Allowances Inventory		
11	Net Increase (Decrease) in Payables and Accrued Expenses	31,767,362	(1,250,437)
12	Net (Increase) Decrease in Other Regulatory Assets	(4,674,400)	10,565,705
13	Net Increase (Decrease) in Other Regulatory Liabilities	(4,241,041)	(11,754,169)
14	(Less) Allowance for Other Funds Used During Construction	4,054,947	2,224,987
15	(Less) Undistributed Earnings from Subsidiary Companies	(1,206,861)	9,971,326
16	Other (footnote details):	13,747,902	(15,854,101)
17	Net Cash Provided by (Used in) Operating Activities		
18	(Total of Lines 2 thru 16)	275,980,953	228,764,858
19			
20	Cash Flows from Investment Activities:		
21	Construction and Acquisition of Plant (including land):		
22	Gross Additions to Utility Plant (less nuclear fuel)	(268,743,138)	(240,025,802)
23	Gross Additions to Nuclear Fuel		
24	Gross Additions to Common Utility Plant		
25	Gross Additions to Nonutility Plant		
26	(Less) Allowance for Other Funds Used During Construction		
27	Other (footnote details):		
28	Cash Outflows for Plant (Total of lines 22 thru 27)	(268,743,138)	(240,025,802)
29			
30	Acquisition of Other Noncurrent Assets (d)		
31	Proceeds from Disposal of Noncurrent Assets (d)		
32	Federal grant payments received	8,277,036	16,927,752
33	Investments in and Advances to Assoc. and Subsidiary Companies	(19,138,510)	(5,482,493)
34	Contributions and Advances from Assoc. and Subsidiary Companies		
35	Disposition of Investments in (and Advances to)		
36	Associated and Subsidiary Companies		
37			
38	Purchase of Investment Securities (a)		
39	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

Statement of Cash Flows (continued)

Line No.	Description (See Instructions for explanation of codes) (a)	Current Year to Date Quarter/Year	Previous Year to Date Quarter/Year
40	Loans Made or Purchased		
41	Collections on Loans		
42			
43	Net (Increase) Decrease in Receivables		
44	Net (Increase) Decrease in Inventory		
45	Net (Increase) Decrease in Allowances Held for Speculation		
46	Net Increase (Decrease) in Payables and Accrued Expenses		
47	Changes in other property and investments	4,540,198	(1,754,160)
48	Net Cash Provided by (Used in) Investing Activities		
49	(Total of lines 28 thru 47)	(275,064,414)	(230,334,703)
50			
51	Cash Flows from Financing Activities:		
52	Proceeds from Issuance of:		
53	Long-Term Debt (b)	80,000,000	85,000,000
54	Preferred Stock		
55	Common Stock	29,078,745	26,462,920
56	Other (footnote details):		
57	Net Increase in Short-term Debt (c)		
58	Cash received for settlement of interest rate swap agreements		
59	Cash Provided by Outside Sources (Total of lines 53 thru 58)	109,078,745	111,462,920
60			
61	Payments for Retirement of:		
62	Long-Term Debt (b)	(11,324,884)	(195,575)
63	Preferred Stock		
64	Common Stock		
65	Other	(19,310,473)	(15,034,097)
66	Net Decrease in Short-Term Debt (c)	(9,000,000)	(49,000,000)
67	Premium paid to repurchase long-term debt		
68	Dividends on Preferred Stock		
69	Dividends on Common Stock	(68,552,375)	(63,736,957)
70	Net Cash Provided by (Used in) Financing Activities		
71	(Total of lines 59 thru 69)	891,013	(16,503,709)
72			
73	Net Increase (Decrease) in Cash and Cash Equivalents		
74	(Total of line 18, 49 and 71)	1,807,552	(18,073,554)
75			
76	Cash and Cash Equivalents at Beginning of Period	1,867,419	19,940,973
77			
78	Cash and Cash Equivalents at End of Period	3,674,971	1,867,419

Name of Respondent	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report 2012/Q4

FOOTNOTE DATA

Schedule Page: 120 Line No.: 65 Column: b	
Settlement of interest rate swap agreement	(18,546,870)
Long-term debt and short-term borrowing issuance costs	(763,603)
Schedule Page: 120 Line No.: 65 Column: c	
Settlement of interest rate swap agreement	(10,557,000)
Long-term debt and short-term borrowing issuance costs	(4,477,097)
Schedule Page: 120 Line No.: 16 Column: c	
Power and natural gas deferrals	193,076
Change in special deposits	(14,234,011)
Change in other current assets	(5,795,951)
Non-cash stock compensation	4,147,207
Changes in other non-current assets/liabilities	(816,072)
Net change in receivables allowance	651,650
Schedule Page: 120 Line No.: 16 Column: b	
Power and natural gas deferrals	1,704,991
Change in special deposits	9,792,264
Change in other current assets	1,080,222
Non-cash stock compensation	4,549,448
Changes in other non-current assets/liabilities	(7,388,676)
Net change in receivables allowance	3,973,772
Cash paid for foreign currency hedges	35,881

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1. Provide important disclosures regarding the Balance Sheet, Statement of Income for the Year, Statement of Retained Earnings for the Year, and Statement of Cash Flow, or any account thereof. Classify the disclosures according to each financial statement, providing a subheading for each statement except where a disclosure is applicable to more than one statement. The disclosures must be on the same subject matters and in the same level of detail that would be required if the respondent issued general purpose financial statements to the public or shareholders.
2. Furnish details as to any significant contingent assets or liabilities existing at year end, and briefly explain any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or a claim for refund of income taxes of a material amount initiated by the utility. Also, briefly explain any dividends in arrears on cumulative preferred stock.
3. Furnish details on the respondent's pension plans, post-retirement benefits other than pensions (PBOP) plans, and post-employment benefit plans as required by instruction no. 1 and, in addition, disclose for each individual plan the current year's cash contributions. Furnish details on the accounting for the plans and any changes in the method of accounting for them. Include details on the accounting for transition obligations or assets, gains or losses, the amounts deferred and the expected recovery periods. Also, disclose any current year's plan or trust curtailments, terminations, transfers, or reversions of assets. Entities that participate in multiemployer postretirement benefit plans (e.g. parent company sponsored pension plans) disclose in addition to the required disclosures for the consolidated plan, (1) the amount of cost recognized in the respondent's financial statements for each plan for the period presented, and (2) the basis for determining the respondent's share of the total plan costs.
4. Furnish details on the respondent's asset retirement obligations (ARO) as required by instruction no. 1 and, in addition, disclose the amounts recovered through rates to settle such obligations. Identify any mechanism or account in which recovered funds are being placed (i.e. trust funds, insurance policies, surety bonds). Furnish details on the accounting for the asset retirement obligations and any changes in the measurement or method of accounting for the obligations. Include details on the accounting for settlement of the obligations and any gains or losses expected or incurred on the settlement.
5. Provide a list of all environmental credits received during the reporting period.
6. Provide a summary of revenues and expenses for each tracked cost and special surcharge.
7. Where Account 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these item. See General Instruction 17 of the Uniform System of Accounts.
8. Explain concisely any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
9. Disclose details on any significant financial changes during the reporting year to the respondent or the respondent's consolidated group that directly affect the respondent's gas pipeline operations, including: sales, transfers or mergers of affiliates, investments in new partnerships, sales of gas pipeline facilities or the sale of ownership interests in the gas pipeline to limited partnerships, investments in related industries (i.e., production, gathering), major pipeline investments, acquisitions by the parent corporation(s), and distributions of capital.
10. Explain concisely unsettled rate proceedings where a contingency exists such that the company may need to refund a material amount to the utility's customers or that the utility may receive a material refund with respect to power or gas purchases. State for each year affected the gross revenues or costs to which the contingency relates and the tax effects and explain the major factors that affect the rights of the utility to retain such revenues or to recover amounts paid with respect to power and gas purchases.
11. Explain concisely significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purchases, and summarize the adjustments made to balance sheet, income, and expense accounts.
12. Explain concisely only those significant changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also give the approximate dollar effect of such changes.
13. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
14. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
15. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

NOTES TO FINANCIAL STATEMENTS

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Business

Avista Corporation (Avista Corp. or the Company) is an energy company engaged in the generation, transmission and distribution of energy, as well as other energy-related businesses. Avista Corp. generates, transmits and distributes electricity in parts of eastern Washington and northern Idaho. In addition, Avista Corp. has electric generating facilities in Montana and northern Oregon. Avista Corp. also provides natural gas distribution service in parts of eastern Washington and northern Idaho, as well as parts of northeastern and southwestern Oregon. Avista Capital, Inc. (Avista Capital), a wholly owned subsidiary of Avista Corp., is the parent company of all of the subsidiary companies, except Spokane Energy, LLC (Spokane Energy). Avista Capital's subsidiaries include Ecova, Inc. (Ecova), a 79.0 percent owned subsidiary as of December 31, 2012. Ecova is a provider of energy efficiency and other facility information and cost management programs and services for multi-site customers and utilities throughout North America.

Basis of Reporting

The financial statements include the assets, liabilities, revenues and expenses of the Company and have been prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission (FERC) as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America (U.S. GAAP). As required by the FERC, the Company accounts for its investment in majority-owned subsidiaries on the equity method rather than consolidating the assets, liabilities, revenues, and expenses of these subsidiaries, as required by U.S. GAAP. The accompanying financial statements include the Company's proportionate share of utility plant and related operations resulting from its interests in jointly owned plants. In addition, under the requirements of the FERC, there are differences from U.S. GAAP in the presentation of (1) current portion of long-term debt (2) assets and liabilities for cost of removal of assets, (3) assets held for sale, (4) regulatory assets and liabilities, (5) deferred income taxes and (6) comprehensive income.

Use of Estimates

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

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

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

System of Accounts

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

Regulation

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

Operating Revenues

Revenues related to the sale of energy are recorded when service is rendered or energy is delivered to customers. The determination of the energy sales to individual customers is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each calendar month, the amount of energy delivered to customers since the date of the last meter reading is estimated and the corresponding unbilled revenue is estimated and recorded.

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

	2012	2011
Unbilled accounts receivable	$ 77,298	$ 82,950

Advertising Expenses

The Company expenses advertising costs as incurred. Advertising expenses were not a material portion of the Company's operating expenses in 2012 and 2011.

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:

	2012	2011
Ratio of depreciation to average depreciable property	2.92%	2.92%

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

- electric thermal production - 33 years,
- hydroelectric production - 73 years,
- electric transmission - 51 years,
- electric distribution - 38 years, and
- natural gas distribution property - 49 years.

Taxes Other Than Income Taxes

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

	2012	2011
Utility taxes	$ 53,716	$ 55,739

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:

	2012	2011
Effective AFUDC rate	7.62%	7.91%

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 17 for further information.

Cash and Cash Equivalents

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

Allowance for Doubtful Accounts

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

Utility Plant in Service

The cost of additions to utility plant in service, including an allowance for funds used during construction and replacements of units of property and improvements, is capitalized. The cost of depreciable units of property retired plus the cost of removal less salvage is charged to accumulated depreciation.

Derivative Assets and Liabilities

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

The Washington Utilities and Transportation Commission (UTC) and the Idaho Public Utilities Commission (IPUC) issued accounting orders authorizing Avista Corp. to offset commodity derivative assets or liabilities with a regulatory asset or liability. This accounting treatment is intended to defer the recognition of mark-to-market gains and losses on energy commodity transactions until the period of settlement. 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 settlement, subject to approval for recovery through retail rates. Realized gains and losses, subject to regulatory approval, result in adjustments to retail rates through purchased gas cost adjustments, the Energy Recovery Mechanism (ERM) in Washington, the Power Cost Adjustment (PCA) mechanism in Idaho, and periodic general rates cases. Regulatory assets are assessed regularly and are probable for recovery through future rates.

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

Fair Value Measurements

Fair value represents the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. Energy commodity derivative assets and liabilities, deferred compensation assets, as well as derivatives related to interest rate swap agreements and foreign currency exchange contracts, are reported at estimated fair value on the Balance Sheets. See Note 15 for the Company's fair value disclosures.

Regulatory Deferred Charges and Credits

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

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

Regulatory accounting practices require that certain costs and/or obligations (such as incurred power and natural gas costs not currently 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 20 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.

Contingencies

The Company has unresolved regulatory, legal and tax issues which have inherently uncertain outcomes. The Company accrues a loss contingency if it is probable that a liability has been incurred and the amount of the loss or impairment can be reasonably estimated. The Company also discloses losses that do not meet these conditions for accrual, if there is a reasonable possibility that a loss may be incurred.

NOTE 2. NEW ACCOUNTING STANDARDS

Effective January 1, 2012, the Company adopted Accounting Standards Update (ASU) No. 2011-04, "Fair Value Measurement (Topic 820): Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs." This ASU requires enhanced disclosures for fair value measurements, including quantitative analysis of unobservable inputs used in Level 3 fair value measurements. The ASU also clarifies the FASB's intent about the application of existing fair value measurement requirements. The adoption of this ASU did not have any impact on the Company's financial condition, results of operations and cash flows. See Note 15 for the Company's fair value disclosures.

In February 2013, the FASB issued ASU No. 2013-02, "Comprehensive Income (Topic 220): Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income." This ASU does not change current requirements for reporting net income or other comprehensive income in financial statements; however, it will require entities to disclose the effect on the line items of net income for reclassifications out of accumulated other comprehensive income if the item being reclassified is required to be reclassified in its entirety to net income under U.S. GAAP. For other items that are not required to be reclassified in their entirety to net income under U.S. GAAP, an entity is required to cross-reference other disclosures required under U.S. GAAP to provide additional detail about those items. This ASU is effective for fiscal years beginning after December 15, 2012. The Company does not expect that this ASU will have any material impact on its financial condition, results of operations and cash flows.

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

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

NOTE 3. VOLUNTARY SEVERANCE INCENTIVE PROGRAM

On October 22, 2012, Avista Corp. announced a voluntary severance incentive program to reduce the total utility workforce and achieve necessary long-term, sustainable, Company-wide savings, in addition to other cost saving measures.

In general, most regular full and part-time employees of Avista Corp. (not including any of its subsidiaries) who were not covered by a collective bargaining agreement were eligible to participate in the program. Based on the response to the program by interested employees and the approvals by Company management, the program resulted in the termination of 55, or approximately 6 percent, of the eligible 919 non-union employees, and the total severance costs under the program were $7.3 million (pre-tax). The total severance costs are made up of the severance payments and the related payroll taxes and employee benefit costs. Approximately 50 percent of the applicants to the program were approved for termination by Company management. The long-term operating and maintenance cost savings under the program are expected to exceed the severance costs of the program and the expected payback period for the severance costs will be approximately 1.4 years.

Each participant in the program was entitled to receive severance pay in an amount calculated by reference to the participant's years of service and base pay as of December 31, 2012. In no event did the amount of severance pay exceed 78 weeks of a participant's base pay.

All terminations under the voluntary severance incentive program were completed by December 31, 2012. The cost of the program was recognized as expense during the fourth quarter of 2012 and severance pay was distributed in a single lump sum cash payment to each participant during January 2013.

NOTE 4. ECOVA ACQUISITIONS

The acquisition of Cadence Network in July 2008 was funded by issuing additional Ecova common stock. Under the transaction agreement, the previous owners of Cadence Network had a right to have their shares of Ecova common stock redeemed by Ecova during July 2011 or July 2012 if their investment in Ecova was not liquidated through either an initial public offering or sale of the business to a third party. These redemption rights were not exercised and expired effective July 31, 2012. As such, this redeemable noncontrolling interest was reclassified to equity effective July 31, 2012. Additionally, certain minority shareholders and option holders of Ecova have the right to put their shares back to Ecova at their discretion during an annual put window. Stock options and other outstanding redeemable stock are valued at their maximum redemption amount which is equal to their intrinsic value (fair value less exercise price).

In January 2011, Ecova acquired substantially all of the assets and liabilities of Building Knowledge Networks, LLC (BKN), a Seattle-based real-time building energy management services provider.

On November 30, 2011, Ecova acquired all of the capital stock of Prenova, Inc. (Prenova), an Atlanta-based energy management company.

On January 31, 2012, Ecova acquired all of the capital stock of LPB Energy Management (LPB), a Dallas, Texas-based energy management company.

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 its resource procurement and management operations in the electric business, Avista Corp. engages in an ongoing process of resource optimization, which involves the economic selection from available energy resources to serve Avista Corp.'s load obligations and the use of these resources to capture available economic value. Avista Corp. 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 our load obligations and hedging the related financial risks. These transactions range from terms of intra-hour up to multiple years.

Avista Corp. makes continuing projections of:

- electric loads at various points in time (ranging from intra-hour to multiple years) based on, among other things, estimates of customer usage and weather, historical data and contract terms, and
- resource availability at these points in time based on, among other things, fuel choices and fuel markets, estimates of streamflows, availability of generating units, historic and forward market information, contract terms, and experience.

On the basis of these projections, we make purchases and sales of electric capacity and energy, fuel for electric generation, and related derivative instruments to match expected resources to expected electric load requirements and reduce our exposure to electricity (or fuel) market price changes. Resource optimization involves generating plant dispatch and scheduling available resources and also includes transactions such as:

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

Avista Corp.'s optimization process includes entering into hedging transactions to manage risks. Transactions include both physical energy contracts and related derivative 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, 2012 that are expected to settle 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 mmBTUs	Financial mmBTUs	Physical MWH	Financial MWH	Physical mmBTUs	Financial mmBTUs
2013	713	3,365	18,523	88,391	264	2,712	7,252	91,962
2014	397	801	6,394	55,407	377	1,844	1,786	33,623
2015	379	614	3,390	42,930	286	982	—	35,575
2016	367	—	1,365	455	287	—	—	—
2017	366	—	—	—	286	—	—	—
Thereafter	583	—	—	—	443	—	—	—

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

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

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 sixty days with U.S. dollars. Avista Corp. economically 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):

	2012	2011
Number of contracts	20	28
Notional amount (in United States dollars)	$ 12,621	$ 7,033
Notional amount (in Canadian dollars)	12,502	7,192

Interest Rate Swap Agreements

Avista Corp. 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 swap agreements are considered economic hedges against fluctuations in future cash flows associated with anticipated debt issuances.

The following table summarizes the interest rate swaps that the Company has entered into as of December 31 (dollars in thousands):

	2012	2011
Number of contracts	—	3
Notional amount	$ —	$ 75,000
Mandatory cash settlement date	—	July 2012
Number of contracts	2	2

Notional amount	$ 85,000	$ 85,000
Mandatory cash settlement date	June 2013	June 2013
Number of contracts	2	—
Notional amount	$ 50,000	$ —
Mandatory cash settlement date	October 2014	—
Number of contracts	1	—
Notional amount	$ 25,000	$ —
Mandatory cash settlement date	October 2015	—

In May 2012, the Company cash settled interest rate swap contracts (notional amount of $75.0 million) and paid a total of $18.5 million. The interest rate swap contracts were settled in connection with the pricing of $80.0 million of First Mortgage Bonds. In September 2011, the Company cash settled interest rate swap contracts (notional amount of $85.0 million) and paid a total of $10.6 million. The interest rate swap contracts were settled in connection with the pricing of $85.0 million of First Mortgage Bonds.

Upon settlement of the 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 life of the forecasted interest payments.

Derivative Instruments Summary

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

		Fair Value			
Derivative	Balance Sheet Location	Asset	Liability	Collateral Netting	Net Asset (Liability)
Foreign currency contracts	Derivative instrument liabilities –Hedges	$ 7	$ (34)	$ —	$ (27)
Interest rate contracts	Derivative instrument liabilities -Hedges	—	(1,406)	—	(1,406)
Interest rate contracts	Long-term portion of derivative instrument assets -Hedges	7,265	—	—	7,265
Commodity contracts	Derivative instrument assets current	10,772	(6,633)	—	4,139
Commodity contracts	Long-term portion of derivative assets	18,779	(17,686)	—	1,093
Commodity contracts	Derivative instrument liabilities current	50,227	(89,449)	9,707	(29,515)
Commodity contracts	Long-term portion of derivative liabilities	2,247	(28,558)	—	(26,311)
Total derivative instruments recorded on the balance sheet		$ 89,297	$ (143,766)	$ 9,707	$ (44,762)

The following table presents the fair values and locations of derivative instruments recorded on the Balance Sheet as of December 31, 2011 (in thousands):

		Fair Value		
Derivative	Balance Sheet Location	Asset	Liability	Net Asset (Liability)
Foreign currency contracts	Derivative instrument assets –Hedges	$ 32	$ —	$ 32
Interest rate contracts	Derivative instrument liabilities –Hedges	—	(16,253)	(16,253)
Interest rate contracts	Long-term portion of derivative instrument liabilities - Hedges	—	(2,642)	(2,642)
Commodity contracts	Derivative instrument assets current	1,618	(479)	1,139
Commodity contracts	Long-term portion of derivative assets	185	—	185
Commodity contracts	Derivative instrument liabilities current	40,090	(110,914)	(70,824)

Commodity contracts	Long-term portion of derivative instrument liabilities	44,308	(84,838)	(40,530)
Total derivative instruments recorded on the balance sheet		$ 86,233	$ (215,126)	$ (128,893)

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, 2012, the Company had cash deposited as collateral of $10.1 million and letters of credit of $28.1 million outstanding related to its energy derivative contracts. The Balance Sheet at December 31, 2012 reflects the offsetting of $9.7 million of cash collateral against net derivative positions where a legal right of offset exists.

Certain of the Company's derivative instruments contain provisions that require the Company to maintain an investment grade credit rating from the major credit rating agencies. If the Company's credit ratings were to fall below "investment grade," it would be in violation of these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position as of December 31, 2012 was $35.9 million. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2012, the Company could be required to post $25.8 million of additional collateral to its counterparties.

Credit Risk

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

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

Changes in market prices may dramatically alter the size of credit risk with counterparties, even when conservative credit limits are established. Should a counterparty fail to perform, the Company may be required to honor the underlying commitment or to replace existing contracts with contracts at then-current market prices.

We enter into bilateral transactions between Avista and various counterparties. We also trade energy and related derivative instruments through clearinghouse exchanges.

The Company seeks to mitigate bilateral credit risk by:

- entering into bilateral contracts that specify credit terms and protections against default,
- applying credit limits and duration criteria to existing and prospective counterparties,
- actively monitoring current credit exposures,
- asserting our collateral rights with counterparties,
- carrying out transaction settlements timely and effectively, and
- conducting transactions on exchanges with fully collateralized clearing arrangements that significantly reduce counterparty default risk.

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

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

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

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

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

NOTE 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):

	2012	2011
Utility plant in service	$ 344,958	$ 342,539
Accumulated depreciation	(234,126)	(225,746)

NOTE 7. ASSET RETIREMENT OBLIGATIONS

The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the associated costs of the asset retirement obligation are capitalized as part of the carrying amount of the related long-lived asset. The liability is accreted to its present value each period and the related capitalized costs are depreciated over the useful life of the related asset. Upon retirement of the asset, the Company either settles the retirement obligation for its recorded amount or incurs a gain or loss. The Company records regulatory assets and liabilities for the difference between asset retirement costs currently recovered in rates and asset retirement obligations recorded since asset retirement costs are recovered through rates charged to customers. The regulatory assets do not earn a return.

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

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

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

- removal and disposal of certain transmission and distribution assets, and

- abandonment and decommissioning of certain hydroelectric generation and natural gas storage facilities.

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

	2012	2011
Asset retirement obligation at beginning of year	$ 3,513	$ 3,887
New liability recognized	—	—
Liability settled	(559)	(612)
Accretion expense	214	238
Asset retirement obligation at end of year	$ 3,168	$ 3,513

NOTE 8. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

The Company has a defined benefit pension plan covering substantially all regular full-time employees at Avista Corp. Individual benefits under this plan are based upon the employee's years of service, date of hire and average compensation as specified in the plan. The Company's funding policy is to contribute at least the minimum amounts that are required to be funded under the Employee Retirement Income Security Act, but not more than the maximum amounts that are currently deductible for income tax purposes. The Company contributed $44 million in cash to the pension plan in 2012 and $26 million in 2011. The Company expects to contribute $44 million in cash to the pension plan in 2013.

The Company also has a Supplemental Executive Retirement Plan (SERP) that provides additional pension benefits to executive officers of the Company. The SERP is intended to provide benefits to executive officers whose benefits under the pension plan are reduced due to the application of Section 415 of the Internal Revenue Code of 1986 and the deferral of salary under deferred compensation plans. The liability and expense for this plan are included as pension benefits in the tables included in this Note.

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

	2013	2014	2015	2016	2017	Total 2018-2022
Expected benefit payments	$ 24,504	$ 24,280	$ 25,434	$ 26,567	$ 27,797	$ 162,488

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

The Company provides certain health care and life insurance benefits for substantially all of its retired employees. The Company accrues the estimated cost of postretirement benefit obligations during the years that employees provide services. The Company elected to amortize the transition obligation of $34.5 million over a period of 20 years, beginning in 1993.

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):

	2013	2014	2015	2016	2017	Total 2018-2022
Expected benefit payments	$ 6,099	$ 6,160	$ 6,261	$ 6,389	$ 6,571	$ 36,342

The Company expects to contribute $6.1 million to other postretirement benefit plans in 2013, 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.

Name of Respondent	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report 2012/Q4

Notes to Financial Statements

The following table sets forth the pension and other postretirement benefit plan disclosures as of December 31, 2012 and 2011 and the components of net periodic benefit costs for the years ended December 31, 2012 and 2011 (dollars in thousands):

	Pension Benefits		Other Post-retirement Benefits	
	2012	2011	2012	2011
Change in benefit obligation:				
Benefit obligation as of beginning of year	$ 494,192	$ 433,491	$ 104,730	$ 60,339
Service cost	15,551	12,936	2,804	1,805
Interest cost	24,349	24,134	5,056	4,126
Actuarial loss	72,170	44,148	24,543	42,476
Transfer of accrued vacation	—	—	336	450
Benefits paid	(21,643)	(20,517)	(4,928)	(4,466)
Benefit obligation as of end of year	$ 584,619	$ 494,192	$ 132,541	$ 104,730
Change in plan assets:				
Fair value of plan assets as of beginning of year	$ 328,150	$ 306,712	$ 22,455	$ 22,875
Actual return on plan assets	54,318	14,705	2,833	(420)
Employer contributions	44,000	26,000	—	—
Benefits paid	(20,407)	(19,267)	—	—
Fair value of plan assets as of end of year	$ 406,061	$ 328,150	$ 25,288	$ 22,455
Funded status	$ (178,558)	$ (166,042)	$ (107,253)	$ (82,275)
Unrecognized net actuarial loss	223,308	192,883	94,202	76,187
Unrecognized prior service cost	319	665	(856)	(1,005)
Unrecognized net transition obligation	—	—	—	505
Prepaid (accrued) benefit cost	45,069	27,506	(13,907)	(6,588)
Additional liability	(223,627)	(193,548)	(93,346)	(75,687)
Accrued benefit liability	$ (178,558)	$ (166,042)	$ (107,253)	$ (82,275)
Accumulated pension benefit obligation	$ 505,695	$ 429,135	—	—
Accumulated postretirement benefit obligation:				
For retirees			$ 49,232	$ 39,470
For fully eligible employees			$ 35,570	$ 29,597
For other participants			$ 47,739	$ 35,663
Included in accumulated comprehensive loss (income) (net of tax):				
Unrecognized net transition obligation	$ —	$ —	$ —	$ 328
Unrecognized prior service cost	207	433	(556)	(653)
Unrecognized net actuarial loss	145,150	125,374	61,231	49,522
Total	145,357	125,807	60,675	49,197
Less regulatory asset	(138,184)	(119,360)	(60,981)	(49,873)
Accumulated other comprehensive loss (income)	$ 7,173	$ 6,447	$ (306)	$ (676)

	Pension Benefits		Other Post-retirement Benefits	
	2012	2011	2012	2011
Weighted average assumptions as of December 31:				
Discount rate for benefit obligation	4.15%	5.04%	4.15%	4.98%
Discount rate for annual expense	5.04%	5.68%	4.98%	5.53%
Expected long-term return on plan assets	6.95%	7.40%	6.55%	7.00%
Rate of compensation increase	4.89%	4.87%		
Medical cost trend pre-age 65 – initial			7.00%	7.50%
Medical cost trend pre-age 65 – ultimate			5.00%	5.00%
Ultimate medical cost trend year pre-age 65			2019	2017
Medical cost trend post-age 65 – initial			7.50%	8.00%
Medical cost trend post-age 65 – ultimate			5.00%	6.00%

Ultimate medical cost trend year post-age 65	2021	2018

	Pension Benefits		Other Postretirement Benefits	
	2012	2011	2012	2011
Components of net periodic benefit cost:				
Service cost	$ 15,551	$ 12,936	$ 2,804	$ 1,805
Interest cost	24,349	24,134	5,056	4,126
Expected return on plan assets	(23,810)	(23,115)	(1,471)	(1,601)
Transition obligation recognition	—	—	505	505
Amortization of prior service cost	346	475	(149)	(149)
Net loss recognition	11,637	9,493	5,020	3,458
Net periodic benefit cost	$ 28,073	$ 23,923	$ 11,765	$ 8,144

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 primarily in marketable debt and equity securities. Pension plan assets may also be invested in real estate, absolute return, venture capital/private equity 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 as indicated in the table below:

	2012	2011
Equity securities	51%	51%
Debt securities	31%	31%
Real estate	5%	5%
Absolute return	10%	10%
Other	3%	3%

The market-related value of pension plan assets invested in debt and equity securities was based primarily on fair value (market prices). The fair value of investment securities traded on a national securities exchange is determined based on the 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). 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, 2012 and 2011.

The following table discloses by level within the fair value hierarchy (see Note 15 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2012 at fair value (dollars in thousands):

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

The following table discloses by level within the fair value hierarchy (see Note 15 for a description of the fair value hierarchy) of the pension plan's assets measured and reported as of December 31, 2011 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 7,550	$ —	$ 7,550
Mutual funds:				
Fixed income securities	76,486	—	—	76,486
U.S. equity securities	102,790	—	—	102,790
International equity securities	52,241	—	—	52,241
Absolute return (1)	16,121	—	—	16,121
Commodities (2)	6,526	—	—	6,526
Common/collective trusts:				
Fixed income securities	—	27,774	—	27,774
U.S. equity securities	—	12,669	—	12,669
Real estate	—	—	8,598	8,598
Partnership/closely held investments:				
Absolute return (1)	—	—	16,587	16,587
Private equity funds (3)	—	—	808	808
Total	$ 254,164	$ 47,993	$ 25,993	$ 328,150

(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) The fund primarily invests in derivatives linked to commodity indices to gain exposure to the commodity markets. The fund manager fully collateralizes these positions 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, 2012 (dollars in thousands):

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

The 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, 2011 (dollars in thousands):

	Common/collective trusts		Partnership/closely held investments	
	Absolute return	Real estate	Absolute return	Private equity funds
Balance, as of January 1, 2011	$ 95	$ 423	$ 16,917	$ 1,272
Realized gains (losses)	(748)	22	—	373
Unrealized gains (losses)	746	1,098	(330)	(218)
Purchases (sales), net	(93)	7,055	—	(619)
Balance, as of December 31, 2011	$ —	$ 8,598	$ 16,587	$ 808

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 62 percent equity securities and 38 percent debt securities in 2012 and 2011.

The market-related value of other postretirement plan assets was determined as of December 31, 2012 and 2011.

The following table discloses by level within the fair value hierarchy (see Note 15 for a description of the fair value hierarchy) of other postretirement plan assets measured and reported as of December 31, 2012 at fair value (dollars in thousands):

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

The following table discloses by level within the fair value hierarchy (see Note 15 for a description of the fair value hierarchy) of other postretirement plan assets measured and reported as of December 31, 2011 at fair value (dollars in thousands):

	Level 1	Level 2	Level 3	Total
Cash equivalents	$ —	$ 86	$ —	$ 86
Mutual funds:				
Fixed income securities	8,683	—	—	8,683
U.S. equity securities	7,278	—	—	7,278
International equity securities	4,766	—	—	4,766
U.S. equity securities	1,569	—	—	1,569
Other	73	—	—	73
Total	$ 22,369	$ 86	$ —	$ 22,455

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, 2012 by $20.8 million and the service and interest cost by $1.4 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, 2012 by $16.7 million and the service and interest cost by $1.1 million.

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

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

	2012	2011
Employer 401(k) matching contributions	$ 5,813	$ 5,452

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):

	2012	2011
Deferred compensation assets and liabilities	$ 8,806	$ 8,653

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 carryforwards. As of December 31, 2012, the Company had $13.9 million of state tax credit carryforwards. State tax credits expire from 2015 to 2025. The Company recognizes the effect of state tax credits generated from utility plant as they are utilized.

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

The Company and its eligible subsidiaries file consolidated federal income tax returns. The Company also files state income tax returns in certain jurisdictions, including Idaho, Oregon and Montana. Subsidiaries are charged or credited with the tax effects of their operations on a stand-alone basis. The Internal Revenue Service (IRS) has completed its examination of all tax years through 2009 and all issues were resolved related to these years. The IRS has not completed an examination of the Company's 2010 through 2011 federal income tax returns. The Company does not believe that any open tax years for federal or state income taxes could result in any adjustments that would be significant to the financial statements.

The Company did not incur any penalties on income tax positions in 2012 or 2011.

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):

	2012	2011
Regulatory assets for deferred income taxes	$ 79,406	$ 84,576

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 2055. Total expenses for power purchased, natural gas purchased, fuel for generation and other fuel costs were as follows for the years ended December 31 (dollars in thousands):

	2012	2011
Utility power resources	$ 523,416	$ 557,619

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):

	2013	2014	2015	2016	2017	Thereafter	Total
Power resources	$ 196,877	$ 132,378	$ 118,054	$ 117,779	$ 116,580	$ 1,025,941	$ 1,707,609
Natural gas resources	109,406	96,092	77,688	60,104	51,950	678,042	1,073,282
Total	$ 306,283	$ 228,470	$ 195,742	$ 177,883	$ 168,530	$ 1,703,983	$ 2,780,891

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. 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.

In addition, Avista Corp. has operational agreements, settlements and other contractual obligations for its generation, transmission and distribution facilities. The following table details future contractual commitments for these agreements (dollars in thousands):

	2013	2014	2015	2016	2017	Thereafter	Total
Contractual obligations	$ 30,913	$ 31,732	$ 29,259	$ 35,844	$ 27,708	$ 230,453	$ 385,909

Avista Corp. has fixed contracts with certain Public Utility Districts (PUD) to purchase portions of the output of certain generating facilities. Although Avista Corp. has no investment in the PUD generating facilities, the fixed contracts obligate Avista Corp. to pay certain minimum amounts (based in part on the debt service requirements of the PUD) whether or not the facilities are operating.

Expenses under these PUD contracts were as follows for the years ended December 31 (dollars in thousands):

	2012	2011
PUD contract costs	$ 8,436	$ 10,533

Information as of December 31, 2012 pertaining to these PUD contracts is summarized in the following table (dollars in thousands):

	Company's Current Share of					
	Output	Kilowatt	Annual	Debt Service Costs (1)	Bonds	Expiration
Douglas County PUD:						
Wells Project	3.4%	24,048	2,716	874	3,117	2018
Grant County PUD:						
Priest Rapids and Wanapum Projects	3.3%	65,800	5,717	2,425	30,655	2055
Totals		89,848	$ 8,433	$ 3,299	$ 33,772	

(1) The annual costs will change in proportion to the percentage of output allocated to Avista Corp. in a particular year. Amounts represent the operating costs for 2012. Debt service costs are included in annual costs.

The estimated aggregate amounts of required minimum payments (Avista Corp.'s share of existing debt service costs) under these PUD contracts are as follows (dollars in thousands):

	2013	2014	2015	2016	2017	Thereafter	Total
Minimum payments	$ 3,348	$ 3,332	$ 3,223	$ 3,222	$ 3,220	$ 42,988	$ 59,333

In addition, Avista Corp. will be required to pay its proportionate share of the variable operating expenses of these projects.

NOTE 11. NOTES PAYABLE

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

The committed line of credit is secured by non-transferable First Mortgage Bonds of the Company issued to the agent bank that would only become due and payable in the event, and then only to the extent, that the Company defaults on its obligations under the committed line of credit.

The committed line of credit agreement contains customary covenants and default provisions. The credit agreement has a covenant which does not permit the ratio of "consolidated total debt" to "consolidated total capitalization" of Avista Corp. to be greater than 65 percent at any time. As of December 31, 2012, 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):

	2012	2011
Balance outstanding at end of period	$ 52,000	$ 61,000
Letters of credit outstanding at end of period	$ 35,885	$ 29,030
Average interest rate at end of period	1.12%	1.12%

NOTE 12. BONDS

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

Maturity Year	Description	Interest Rate	2012	2011
2012	Secured Medium-Term Notes	7.37%	$ —	$ 7,000
2013	First Mortgage Bonds	1.68%	50,000	50,000

2018	First Mortgage Bonds	5.95%	250,000	250,000
2018	Secured Medium-Term Notes	7.39%-7.45%	22,500	22,500
2019	First Mortgage Bonds	5.45%	90,000	90,000
2020	First Mortgage Bonds	3.89%	52,000	52,000
2022	First Mortgage Bonds	5.13%	250,000	250,000
2023	Secured Medium-Term Notes	7.18%-7.54%	13,500	13,500
2028	Secured Medium-Term Notes	6.37%	25,000	25,000
2032	Secured Pollution Control Bonds (1)	(1)	66,700	66,700
2034	Secured Pollution Control Bonds (2)	(2)	17,000	17,000
2035	First Mortgage Bonds	6.25%	150,000	150,000
2037	First Mortgage Bonds	5.70%	150,000	150,000
2040	First Mortgage Bonds	5.55%	35,000	35,000
2041	First Mortgage Bonds	4.45%	85,000	85,000
2047	First Mortgage Bonds (3)	4.23%	80,000	—
	Total secured bonds		1,336,700	1,263,700
2023	Unsecured Pollution Control Bonds	6.00%	—	4,100
	Settled interest rate swaps		(27,900)	(10,629)
	Secured Pollution Control Bonds held by Avista Corporation (1) (2)		(83,700)	(83,700)
	Total bonds		$ 1,225,100	$ 1,173,471

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

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

(3) In November 2012, the Company issued $80.0 million of 4.23 percent First Mortgage Bonds due in 2047.

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

	2013	2014	2015	2016	2017	Thereafter	Total
Debt maturities	$ 50,000	$ —	$ —	$ —	$ —	$ 1,254,547	$ 1,304,547

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, 2012, property additions and retired bonds would have allowed, and the net earnings test would not have prohibited the issuance of $640.1 million in aggregate principal amount of additional First Mortgage Bonds.

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:

	2012	2011
Low distribution rate	1.19%	1.13%
High distribution rate	1.40	1.40
Distribution rate at the end of the year	1.19	1.40

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. LEASES

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

	2012	2011
Rental expense	$ 3,274	$ 2,853

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

	2013	2014	2015	2016	2017	Thereafter	Total
Minimum payments required	$ 1,749	$ 1,517	$ 498	$ 162	$ 148	$ 2,712	$ 6,786

NOTE 15. FAIR VALUE

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

The 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):

	2012		2011	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Bonds (Level 2)	$ 951,000	$ 1,164,639	$ 962,100	$ 1,135,536
Bonds (Level 3)	302,000	320,892	222,000	234,226
Advances from associated companies (Level 3)	51,547	43,686	51,547	43,810

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

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 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, 2012 and 2011 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, 2012					
Assets:					
Energy commodity derivatives	$ —	$ 81,640	$ —	$ (76,408)	$ 5,232
Level 3 energy commodity derivatives:					
Power exchange agreements	—	—	385	(385)	—
Foreign currency derivatives	—	7	—	(7)	—
Interest rate swaps	—	7,265	—	—	7,265
Deferred compensation assets:					
Fixed income securities	2,010	—	—	—	2,010
Equity securities	5,955	—	—	—	5,955
Total	$ 7,965	$ 88,912	$ 385	$ (76,800)	$ 20,462
Liabilities:					
Energy commodity derivatives	$ —	$ 119,390	$ —	$ (86,115)	$ 33,275
Level 3 energy commodity derivatives:					
Natural gas exchange agreements	—	—	2,379	—	2,379
Power exchange agreements	—	—	19,077	(385)	18,692
Power option agreements	—	—	1,480	—	1,480
Foreign currency derivatives	—	34	—	(7)	27
Interest rate swaps	—	1,406	—	—	1,406
Total	$ —	$ 120,830	$ 22,936	$ (86,507)	$ 57,259

	Level 1	Level 2	Level 3	Counterparty and Cash Collateral Netting (1)	Total
December 31, 2011					
Assets:					
Energy commodity derivatives	$ —	$ 80,571	$ —	$ (79,247)	$ 1,324
Level 3 energy commodity derivatives:					
Natural gas exchange agreements	—	—	956	(956)	—
Power exchange agreements	—	—	4,674	(4,674)	—
Foreign currency derivatives	—	32	—	—	32
Deferred compensation assets:					
Fixed income securities	2,116	—	—	—	2,116
Equity securities	5,252	—	—	—	5,252
Total	$ 7,368	$ 80,603	$ 5,630	$ (84,877)	$ 8,724
Liabilities:					
Energy commodity derivatives	$ —	$ 177,743	$ —	$ (79,247)	$ 98,496
Level 3 energy commodity derivatives:					
Natural gas exchange agreements	—	—	2,644	(956)	1,688
Power exchange agreements	—	—	14,584	(4,674)	9,910
Power option agreements	—	—	1,260	—	1,260
Interest rate swaps	—	18,895	—	—	18,895
Total	$ —	$ 196,638	$ 18,488	$ (84,877)	$ 130,249

(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, 2012 and $1.3 million as of December 31, 2011.

Level 3 Fair Value

For power exchange agreements, 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 power commodity option agreements, 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 2013, and 3) volatility rates for periods beyond January 2016. Significant increases or decreases in any of these inputs in isolation would result in a significantly higher or lower fair value measurement. Generally, changes in overall commodity market prices and volatility rates are accompanied by directionally similar changes in the strike price and volatility assumptions used in the calculation.

For natural gas commodity exchange agreements, 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, 2012 (dollars in thousands):

	Fair Value (Net) at December 31, 2012	Valuation Technique	Unobservable Input	Range
Power exchange agreements	$ (18,692)	Surrogate facility pricing	O&M charges	$30.49-$53.82/MWh (1)
			Escalation factor	5% - 2013 to 2015
				3% - 2016 to 2019
			Transaction volumes	365,619 - 379,156 MWhs
Power option agreements	(1,480)	Black-Scholes-Merton	Strike price	$52.61/MWh - 2013
				$76.63/MWh - 2019
			Delivery volumes	128,491 - 287,147 MWhs
			Volatility rates	0.20 (2)
Natural gas exchange agreements	(2,379)	Internally derived weighted average cost of gas	Forward purchase prices	$3.19 - $3.38/mmBTU
			Forward sales prices	$3.29 - $4.46/mmBTU
			Purchase volumes	135,000 - 465,000 mmBTUs
			Sales volumes	140,010 - 620,000 mmBTUs

(1) The average O&M charges for 2012 were $40.87 per MWh.
(2) The estimated volatility rate of 0.20 is compared to actual quoted volatility rates of 0.33 for 2012 to 0.21 in January 2016.

Avista Corp.'s risk management team and accounting team are responsible for developing the valuation methods described above and both groups report to the Chief Financial Officer. The valuation methods, the significant inputs, and the resulting fair values described above are reviewed on at least a quarterly basis by the risk management team and the accounting team to ensure they provide a reasonable estimate of fair value each reporting period.

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

	Natural Gas Exchange Agreements	Power Exchange Agreements	Power Option	Total
Year ended December 31, 2012:				
Balance as of January 1, 2012	$ (1,688)	$ (9,910)	$ (1,260)	$ (12,858)
Total gains or losses (realized/unrealized):				
Included in net income	—	—	—	—
Included in other comprehensive income	—	—	—	—
Included in regulatory assets/liabilities (1)	343	(15,236)	(220)	(15,113)
Purchases	—	—	—	—
Issuance	—	—	—	—
Settlements	(1,034)	6,454	—	5,420
Transfers to/from other categories	—	—	—	—
Ending balance as of December 31, 2012	$ (2,379)	$ (18,692)	$ (1,480)	$ (22,551)
Year ended December 31, 2011:				
Balance as of January 1, 2011	$ —	$ 15,793	$ (2,334)	$ 13,459
Total gains or losses (realized/unrealized):				
Included in net income	—	—	—	—
Included in other comprehensive income	—	—	—	—
Included in regulatory assets/liabilities (1)	2,621	(28,571)	1,074	(24,876)
Purchases	—	—	—	—
Issuance	—	—	—	—
Settlements	95	2,868	—	2,963
Transfers from other categories (2)	(4,404)	—	—	(4,404)
Ending balance as of December 31, 2011	$ (1,688)	$ (9,910)	$ (1,260)	$ (12,858)

(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 settlement. 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 settlement, 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.

(2) A derivative contract was reclassified from Level 2 to Level 3 during 2011 due to a particular unobservable input becoming more significant to the fair value measurement. There were not any reclassifications between Level 1 and Level 2. The Company's policy is to reclassify identified items as of the end of the reporting period.

NOTE 16. 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 is restricted by provisions of certain covenants applicable to preferred stock contained in the Company's Articles of Incorporation, as amended.

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. As of December 31, 2012, the Company had 1,795,199 shares available to be issued under these agreements.

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

	2012	2011
Shares issued under sales agency agreement	931,191	807,000

The Company has 10 million authorized shares of preferred stock. The Company did not have any preferred stock outstanding as of December 31, 2012 and 2011.

NOTE 17. 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, 2012, 0.7 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, 2012, 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):

	2012	2011
Stock-based compensation expense	$ 5,792	$ 5,756
Income tax benefits	2,027	2,014

Stock Options

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

	2012	2011
Number of shares under stock options:		
Options outstanding at beginning of year	92,499	201,674
Options granted	—	—
Options exercised	(89,499)	(107,575)
Options canceled	—	(1,600)
Options outstanding and exercisable at end of year	3,000	92,499
Weighted average exercise price:		
Options exercised	$ 10.63	$ 12.25
Options canceled	$ —	$ 11.80
Options outstanding and exercisable at end of year	$ 12.41	$ 10.69
Cash received from options exercised (in thousands)	$ 951	$ 1,318
Intrinsic value of options exercised (in thousands)	$ 1,349	$ 1,279
Intrinsic value of options outstanding (in thousands)	$ 35	$ 1,393

Information for options outstanding and exercisable as of December 31, 2012 is as follows:

Exercise Price	Number	Weighted Average Exercise Price	Weighted Average Remaining Life (in years)
$12.41	3,000	12.41	0.35

As of December 31, 2012 and 2011, the Company's stock options were fully vested and expensed.

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, 2012 was 0.7 years. The following table summarizes restricted stock activity for the years ended December 31:

	2012	2011
Unvested shares at beginning of year	93,482	84,134
Shares granted	70,281	50,618
Shares canceled	(790)	(431)
Shares vested	(45,855)	(40,839)
Unvested shares at end of year	117,118	93,482
Weighted average fair value at grant date	$ 25.83	$ 23.06
Unrecognized compensation expense at end of year (in thousands)	$ 1,428	$ 932
Intrinsic value, unvested shares at end of year (in thousands)	$ 2,824	$ 2,407
Intrinsic value, shares vested during the year (in thousands)	$ 1,173	$ 934

Performance Shares

Performance share awards vest after a period of three years and are payable in cash or Avista Corp. common stock at the end of the three-year period. Performance share awards entitle the recipients to dividend equivalent rights, are subject to forfeiture under certain circumstances, and are subject to meeting specific performance conditions. Based on the attainment of the performance condition, the amount of cash paid or common stock issued will range from 0 to 150 percent of the performance shares granted for grants prior to 2011 and 0 to 200 percent for grants in 2011 and after, depending on the change in the value of the Company's common stock relative to an external benchmark. Dividend equivalent rights are accumulated and paid out only on shares that eventually vest.

Performance share awards entitle the grantee to shares of common stock or cash payable once the service condition is satisfied. Based on attainment of the performance condition, grantees may receive 0 to 150 percent of the original shares granted for grants prior to 2011 and 0 to 200 percent for shares granted in 2011 and after. The performance condition used is the Company's Total Shareholder Return performance over a three-year period as compared against other utilities; this is considered a market-based condition. Performance shares may be settled in common stock or cash at the discretion of the Company. Historically, the Company has settled these awards through issuance of stock and intends to continue this practice. These awards vest at the end of the three-year period. Performance shares are equity awards with a market-based condition, which results in the compensation cost for these awards being recognized over the requisite service period, provided that the requisite service period is rendered, regardless of when, if ever, the market condition is satisfied.

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

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

	2012	2011
Risk-free interest rate	0.3%	1.2%
Expected life, in years	3	3
Expected volatility	22.7%	26.9%
Dividend yield	4.5%	4.7%
Weighted average grant date fair value (per share)	$ 26.06	$ 20.79

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

The following summarizes performance share activity:

	2012	2011
Opening balance of unvested performance shares	351,345	325,700
Performance shares granted	181,000	184,600
Performance shares canceled	(4,544)	(2,177)
Performance shares vested	(168,101)	(156,778)
Ending balance of unvested performance shares	359,700	351,345
Intrinsic value of unvested performance shares (in thousands)	$ 8,672	$ 9,047
Unrecognized compensation expense (in thousands)	$ 3,800	$ 2,991

The weighted average remaining vesting period for the Company's performance shares outstanding as of December 31, 2012 was 1.5 years. Unrecognized compensation expense as of December 31, 2012 will be recognized during 2013. The following summarizes the impact of the market condition on the vested performance shares:

	2012	2011
Performance shares vested	168,101	156,778
Impact of market condition on shares vested	(168,101)	(15,678)
Shares of common stock earned	—	141,100
Intrinsic value of common stock earned (in thousands)	$ —	$ 3,633

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

Outstanding performance share awards include a dividend component that is paid in cash. This component of the performance share grants is accounted for as a liability award. These liability awards are revalued on a quarterly basis taking into account the number of awards outstanding, historical dividend rate, and the change in the value of the Company's common stock relative to an external benchmark. Over the life of these awards, the cumulative amount of compensation expense recognized will match the actual cash paid. As of December 31, 2012 and 2011, the Company had recognized compensation expense and a liability of $0.7 million and $1.0 million related to the dividend component of performance share grants.

NOTE 18. COMMITMENTS AND CONTINGENCIES

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

Federal Energy Regulatory Commission Inquiry

In April 2004, the Federal Energy Regulatory Commission (FERC) approved the contested Agreement in Resolution of Section 206 Proceeding (Agreement in Resolution) between Avista Corp., Avista Energy and the FERC's Trial Staff which stated that there was: (1) no evidence that any executives or employees of Avista Corp. or Avista Energy knowingly engaged in or facilitated any improper trading strategy during 2000 and 2001; (2) no evidence that Avista Corp. or Avista Energy engaged in any efforts to manipulate the western energy markets during 2000 and 2001; and (3) no finding that Avista Corp. or Avista Energy withheld relevant information from the FERC's inquiry into the western energy markets for 2000 and 2001 (Trading Investigation). The Attorney General of the State of California (California AG), the California Electricity Oversight Board, and the City of Tacoma, Washington (City of Tacoma) challenged the FERC's decisions approving the Agreement in Resolution, which are now pending before the United States Court of Appeals for the Ninth Circuit (Ninth Circuit). In May 2004, the FERC provided notice that Avista Energy was no longer subject to an investigation reviewing certain bids above $250 per MW in the short-term energy markets operated by the California Independent System Operator (CalISO) and the California Power Exchange (CalPX) from May 1, 2000 to October 2, 2000 (Bidding Investigation). That matter is also pending before the Ninth Circuit, after the California AG, Pacific Gas & Electric (PG&E), Southern California Edison Company (SCE) and the California Public Utilities Commission (CPUC) filed petitions for review in 2005.

Based on the FERC's order approving the Agreement in Resolution in the Trading Investigation and order denying rehearing requests, the Company does not expect that this proceeding will have any material effect on its financial condition, results of operations or cash flows. Furthermore, based on information currently known to the Company regarding the Bidding Investigation and the fact that the FERC Staff did not find any evidence of manipulative behavior, the Company does not expect that this matter will have a material effect on its financial condition, results of operations or cash flows.

California Refund Proceeding

In July 2001, the FERC ordered an evidentiary hearing to determine the amount of refunds due to California energy buyers for purchases made in the spot markets operated by the CalISO and the CalPX during the period from October 2, 2000 to June 20, 2001 (Refund Period). Proposed refunds are based on the calculation of mitigated market clearing prices for each hour. The FERC ruled that if the refunds required by the formula would cause a seller to recover less than its actual costs for the Refund Period, sellers may document these costs and limit their refund liability commensurately. In September 2005, Avista Energy submitted its cost filing claim pursuant to the FERC's August 2005 order. The filing was initially accepted by the FERC, but in March 2011, the FERC ordered Avista Energy to remove any return on equity in a compliance filing with the CalISO, which Avista Energy did in April 2011. A challenge to Avista Energy's cost filing by the California AG, the CPUC, PG&E and SCE was denied in July 2011 as a collateral attack on the FERC's prior orders accepting Avista Energy's cost filing. In July 2011, the California AG, the CPUC, PG&E and SCE filed a petition for review of the FERC's orders regarding Avista Energy's cost filing with the Ninth Circuit.

The 2001 bankruptcy of PG&E resulted in a default on its payment obligations to the CalPX. As a result, Avista Energy has not been paid for all of its energy sales during the Refund Period. Those funds are now in escrow accounts and will not be released until the FERC issues an order directing such release in the California refund proceeding. The CalISO continues to work on its compliance filing for the Refund Period, which will show "who owes what to whom." In July 2011, the FERC accepted the preparatory rerun compliance filings by the CalPX and CalISO, and responded to the CalPX request for guidance on issues related to completing the final determination of "who owes what to whom." The FERC directed both the CalISO and the CalPX to prepare and submit to the FERC their final refund rerun compliance filings. The FERC's order also directs the CalPX to pay past due principal amounts to governmental entities. In February 2012, the FERC denied the challenges made to the July 2011 order by the California AG, the CPUC, PG&E and SCE. As of September 30, 2012, Avista Energy's accounts receivable outstanding related to defaulting parties in California were fully offset by reserves for uncollected amounts and funds collected from the defaulting parties.

In August 2006, the Ninth Circuit upheld October 2, 2000 as the refund effective date for the FPA section 206 refund proceeding, but remanded to the FERC its decision not to consider an FPA section 309 remedy for tariff violations prior to that date. In an order issued in May 2011, the FERC clarified the issues set for hearing for the period May 1, 2000 - October 1, 2000 (Summer Period): (1) which market practices and behaviors constitute a violation of the then-current CalISO, CalPX, and individual seller's tariffs and FERC orders; (2) whether any of the sellers named as respondents in this proceeding engaged in those tariff violations; and (3) whether any such tariff violations affected the market clearing price. The FERC reiterated that the California Parties are expected to be very specific when presenting their arguments and evidence, and that general claims would not suffice. The FERC also gave the California Parties an opportunity to show that exchange transactions with the CalISO during the Refund Period were not just and reasonable. Avista Energy has one exchange transaction with the CalISO. The California AG, the CPUC, PG&E and SCE filed for rehearing of the FERC's May 2011 order, arguing that it improperly denies them a market-wide remedy for the pre-refund period. That request for rehearing was denied in an order issued by FERC on November 2, 2012. The California AG, the CPUC, PG&E and SCE filed a petition for review of the May 2011 and November 2012 orders with the Ninth Circuit on November 7, 2012.

A FERC hearing commenced on April 11, 2012 and concluded on July 19, 2012. On August 27, 2012, the Presiding Administrative Law Judge issued a partial initial decision granting Avista Corp.'s motion for summary disposition, based on the stipulation by the

California Parties that there are no allegations of tariff violations made against Avista Corp. in this proceeding and therefore no tariff violations by Avista Corp. that affected the market clearing price in any hour during the Summer Period. On November 2, 2012, FERC issued an order affirming the partial initial decision and dismissing Avista Corp. from the proceeding, thereby terminating all claims against Avista Corp. for the Summer Period. In the same order, FERC also held that a market-wide remedy would not be appropriate with regard to any respondent during the Summer Period. FERC stated that it is clear that the Ninth Circuit did not mandate a specific remedy on remand and, instead, left it to the FERC's discretion to determine which remedy would be appropriate. On December 3, 2012, the California Parties filed a request for clarification and rehearing of the November 2, 2012 order. On February 15, 2013, the Administrative Law Judge issued an initial decision finding that certain Respondents committed various tariff and other violations that affected the market clearing price in the California organized markets during the Summer Period. The tariff violations identified for Avista Energy are type II and III bidding violations; false export violations; and selling ancillary services without market-based rate authority. The initial decision did not discuss evidence offered by Avista Energy, on an hour by hour basis, rebutting the alleged violations and Avista Energy is currently preparing briefs on exceptions which will identify these errors. With respect to Avista Energy's one exchange transaction with the CalISO during the Refund Period, the judge made no findings with respect to the justness and reasonableness of that transaction, but nonetheless determined that Avista Energy owed approximately $0.2 million in refunds with regard to the transaction.

Because the resolution of the California refund proceeding remains uncertain, legal counsel cannot express an opinion on the extent of the Company's liability, if any. However, based on information currently known, the Company does not expect that the refunds ultimately ordered for the Refund Period would result in a material loss. In the event that the Commission does not overturn the legal and factual errors in the February 15, 2013 initial decision, the Company does not expect that the refunds ultimately ordered for that period would result in a material loss either. This is primarily due to the fact that the FERC orders have stated that any refunds will be netted against unpaid amounts owed to the respective parties and the Company does not believe that refunds would exceed unpaid amounts owed to the Company.

Pacific Northwest Refund Proceeding

In July 2001, the FERC initiated a preliminary evidentiary hearing to develop a factual record as to whether prices for spot market sales of wholesale energy in the Pacific Northwest between December 25, 2000 and June 20, 2001 were just and reasonable. In June 2003, the FERC terminated the Pacific Northwest refund proceedings, after finding that the equities do not justify the imposition of refunds. In August 2007, the Ninth Circuit found that the FERC, in denying the request for refunds, had failed to take into account new evidence of market manipulation in the California energy market and its potential ties to the Pacific Northwest energy market and that such failure was arbitrary and capricious and, accordingly, remanded the case to the FERC, stating that the FERC's findings must be reevaluated in light of the evidence. In addition, the Ninth Circuit concluded that the FERC abused its discretion in denying potential relief for transactions involving energy that was purchased by the California Energy Resources Scheduling (CERS) in the Pacific Northwest and ultimately consumed in California. The Ninth Circuit expressly declined to direct the FERC to grant refunds. The Ninth Circuit denied petitions for rehearing by various parties, and remanded the case to the FERC in April 2009.

On October 3, 2011, the FERC issued an Order on Remand, finding that, in light of the Ninth Circuit's remand order, additional procedures are needed to address possible unlawful activity that may have influenced prices in the Pacific Northwest spot market during the period from December 25, 2000 through June 20, 2001. The Order establishes an evidentiary, trial-type hearing before an Administrative Law Judge (ALJ), and reopens the record to permit parties to present evidence of unlawful market activity during the relevant period. The Order also allows participants to supplement the record with additional evidence on CERS transactions in the Pacific Northwest spot market from January 18, 2001 to June 20, 2001. The Order states that parties seeking refunds must submit evidence demonstrating that specific unlawful market activity occurred, and must demonstrate that such activity directly affected negotiations with respect to the specific contract rate about which they complain. Simply alleging a general link between the dysfunctional spot market in California and the Pacific Northwest spot market will not be sufficient to establish a causal connection between a particular seller's alleged unlawful activities and the specific contract negotiations at issue. Claimants filed notice of their claims on August 17, 2012, and they filed their direct testimony on September 21, 2012. Respondents' filed their answering testimony on December 17, 2012 and staff filed its answering testimony on February 5, 2013. Respondents' cross-answering testimony is due February 22, 2013 and claimants' rebuttal testimony is due March 12, 2013. The hearing is scheduled to begin on April 15, 2013. On July 11, 2012, Avista Energy and Avista Corp. filed settlements of all issues in this docket with regard to the claims made by the City of Tacoma. On September 21, 2012, and September 26, 2012, the FERC issued orders approving the settlements between the City of Tacoma and Avista Corp. and Avista Energy, respectively, thus terminating those claims. The two remaining direct claimants against Avista Corp. and Avista Energy in this proceeding are the City of Seattle, Washington, and the California Attorney General (on behalf of CERS).

Both Avista Corp. and Avista Energy were buyers and sellers of energy in the Pacific Northwest energy market during the period between December 25, 2000 and June 20, 2001 and, are subject to potential claims in this proceeding, and if refunds are ordered by the FERC with regard to any particular contract, could be liable to make payments. The Company cannot predict the outcome of this proceeding or the amount of any refunds that Avista Corp. or Avista Energy could be ordered to make. Therefore, the Company cannot predict the potential impact the outcome of this matter could ultimately have on the Company's results of operations, financial condition or cash flows.

California Attorney General Complaint (the "Lockyer Complaint")

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

In March 2008, the FERC issued an order establishing a trial-type hearing to address "whether any individual public utility seller's violation of the FERC's market-based rate quarterly reporting requirement led to an unjust and unreasonable rate for that particular seller in California during the 2000-2001 period." Purchasers in the California markets were given the opportunity to present evidence that "any seller that violated the quarterly reporting requirement failed to disclose an increased market share sufficient to give it the ability to exercise market power and thus cause its market-based rates to be unjust and unreasonable." In March 2010, the Presiding ALJ granted the motions for summary disposition and found that a hearing was "unnecessary" because the California AG, CPUC, PG&E and SCE "failed to apply the appropriate test to determine market power during the relevant time period." The judge determined that "[w]ithout a proper showing of market power, the California Parties failed to establish a prima facie case." In May 2011, the FERC affirmed "in all respects" the ALJ's decision. In June 2011, the California AG, CPUC, PG&E and SCE filed for rehearing of that order. Those rehearing requests were denied by the FERC on June 13, 2012. On June 20, 2012, the California AG, CPUC, PG&E and SCE filed a petition for review of the FERC's order with the Ninth Circuit. On February 6, 2013, the California AG, CPUC, PG&E, and SCE filed an unopposed motion with the Ninth Circuit, requesting that a briefing schedule be established, such that petitioners' joint opening brief would be due May 17, 2013; respondents' answering brief would be due July 16, 2013; respondent-intervenors' joint brief would be due August 6, 2013; and petitioners' optional joint reply brief would be due September 10, 2013.

Based on information currently known to the Company's management, the Company does not expect that this matter will have a material effect on its financial condition, results of operations or cash flows.

Colstrip Generating Project Complaint

In March 2007, two families that own property near the holding ponds from Units 3 & 4 of the Colstrip Generating Project (Colstrip) filed a complaint against the owners of Colstrip and Hydrometrics, Inc. in Montana District Court. Avista Corp. owns a 15 percent interest in Units 3 & 4 of Colstrip. The plaintiffs alleged that the holding ponds and remediation activities adversely impacted their property. They alleged contamination, decrease in water tables, reduced flow of streams on their property and other similar impacts to their property. They also sought punitive damages, attorney's fees, an order by the court to remove certain ponds, and the forfeiture of profits earned from the generation of Colstrip. In September 2010, the owners of Colstrip filed a motion with the court to enforce a settlement agreement that would resolve all issues between the parties. In October 2011 the court issued an order which enforces the settlement agreement. The plaintiffs subsequently appealed the court's decision and, on December 31, 2012, the Montana Supreme Court issued its decision, holding that the District Court properly granted the motion to enforce the settlement agreement. A petition for rehearing before the Supreme Court was denied on February 5, 2013. Under the settlement, Avista Corp.'s portion of payment (which was accrued in 2010) to the plaintiffs was not material to its financial condition, results of operations or cash flows.

Sierra Club and Montana Environmental Information Center Notice

On July 30, 2012, Avista Corp. received a Notice of Intent to Sue for violations of the Clean Air Act at Colstrip Steam Electric Station (Notice) from counsel on behalf of the Sierra Club and the Montana Environmental Information Center (MEIC), an Amended Notice was received on September 4, 2012, and a Second Amended Notice was received on October 1, 2012. A "supplemental" Notice was received on December 4, 2012. The Notice, Amended Notice, Second Amended Notice and Supplemental Notice were all addressed to the Owner or Managing Agent of Colstrip, and to the other Colstrip co-owners: PPL Montana, Puget Sound Energy, Portland General Electric Company, NorthWestern Energy and PacifiCorp. The Notice alleges certain violations of the Clean Air Act, including the New Source Review, Title V and opacity requirements. The Amended Notice alleges additional opacity violations at Colstrip, and the Second Amended Notice alleges additional Title V allegations. All three notices state that Sierra Club and MEIC will request a United States District Court to impose injunctive relief and civil penalties, require a beneficial environmental project in the areas affected by the alleged air pollution and require reimbursement of Sierra Club's and MEIC's costs of litigation and attorney's fees. Under the Clean Air Act, lawsuits cannot be filed until 60 days after the applicable notice date. Avista Corp. is evaluating the allegations set forth in the Notice, Amended Notice and Second Amended Notice and Supplemental Notice, and cannot at this time predict the outcome of this matter.

Harbor Oil Inc. Site

Avista Corp. used Harbor Oil Inc. (Harbor Oil) for the recycling of waste oil and non-PCB transformer oil in the late 1980s and early 1990s. In June 2005, the Environmental Protection Agency (EPA) Region 10 provided notification to Avista Corp. and several other parties, as customers of Harbor Oil, that the EPA had determined that hazardous substances were released at the Harbor Oil site in Portland, Oregon and that Avista Corp. and several other parties may be liable for investigation and cleanup of the site under the Comprehensive Environmental Response, Compensation, and Liability Act, commonly referred to as the federal "Superfund" law, which provides for joint and several liability. The initial indication from the EPA is that the site may be contaminated with PCBs, petroleum hydrocarbons, chlorinated solvents and heavy metals. Six potentially responsible parties, including Avista Corp., signed an Administrative Order on Consent with the EPA on May 31, 2007 to conduct a remedial investigation and feasibility study (RI/FS). The draft final RI/FS was submitted to the EPA in December 2011 and was accepted as pre-final in March 2012. The EPA issued a notice of its plan to make a finding of No Further Action in November 2012. Should the EPA make a No Further Action determination, the EPA stated it would then propose removal of the site from the National Priority List. Based on the review of its records related to Harbor Oil, the Company does not believe it is a significant contributor to this potential environmental contamination based on the small volume of waste oil it delivered to the Harbor Oil site. As such, the Company does not expect that this matter will have a material effect on its financial condition, results of operations or cash flows. The Company has expensed its share of the RI/FS ($0.5 million) for this matter.

Spokane River Licensing

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

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

The IPUC and the UTC 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. The modification will be tested in 2013 to evaluate whether this approach will provide significant TDG reduction, and whether it could be applied to other spill gates. The Company will continue to seek recovery, through the ratemaking process, of all operating and capitalized costs related to this issue.

Fish Passage at Cabinet Gorge and Noxon Rapids

In 1999, the USFWS listed bull trout as threatened under the Endangered Species Act. The Clark Fork Settlement Agreement describes programs intended to help restore bull trout populations in the project area. Using the concept of adaptive management and working closely with the USFWS, the Company evaluated the feasibility of fish passage at Cabinet Gorge and Noxon Rapids. The results of these studies led, in part, to the decision to move forward with development of permanent facilities, among other bull trout enhancement efforts. As of the end of 2012, fishway design for Cabinet Gorge was still being finalized. Construction cost estimates and schedules will be developed in 2013. Fishway design for Noxon Rapids has also been initiated, and is still in early stages.

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

Aluminum Recycling Site

In October 2009, the Company (through its subsidiary Pentzer Venture Holdings II, Inc. (Pentzer)) received notice from Ecology proposing to find Pentzer liable for a release of hazardous substances under the Model Toxics Control Act, under Washington state law. Pentzer owns property that adjoins land owned by the Union Pacific Railroad (UPR). UPR leased their property to operators of a facility designated by Ecology as "Aluminum Recycling - Trentwood." Operators of the UPR property maintained piles of aluminum dross, which designate as a state-only dangerous waste in Washington State. In the course of its business, the operators placed a portion of the aluminum dross pile on the property owned by Pentzer. Pentzer does not believe it is a contributor to any environmental contamination associated with the dross pile, and submitted a response to Ecology's proposed findings in November 2009. In December 2009, Pentzer received notice from Ecology that it had been designated as a potentially liable party for any hazardous substances located on this site. UPR completed a Remedial Investigation/Feasibility Study during 2011, which was approved by Ecology in 2012. Based on information currently known to the Company's management, the Company does not expect this issue will have a material effect on its financial condition, results of operations or cash flows.

Collective Bargaining Agreements

The Company's collective bargaining agreement with the International Brotherhood of Electrical Workers represents approximately 45 percent of all of Avista Corp.'s employees. The agreement with the local union in Washington and Idaho representing the majority (approximately 90 percent) of the bargaining unit employees expires in March 2014. Two local agreements in Oregon, which cover approximately 50 employees, expire in March 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 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 19. INFORMATION SERVICES CONTRACTS

The Company has information services contracts that expire at various times through 2018. 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 subject to a three-year true-up cycle. Total payments under these contracts were as follows for the years ended December 31 (dollars in thousands):

	2012	2011
Information service contract payments	$ 13,221	$ 13,038

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):

	2013	2014	2015	2016	2017	Thereafter	Total
Contractual obligations	$ 11,175	$ 9,400	$ 8,700	$ 8,700	$ 8,600	$ 900	$ 47,475

NOTE 20. 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 of hydroelectric generation,
- the level of thermal generation (including changes in fuel prices), and
- retail loads.

In Washington, the Energy Recovery Mechanism (ERM) allows Avista Corp. to periodically increase or decrease electric rates with UTC approval to reflect changes in power supply costs. The ERM is an accounting method used to track certain differences between actual net power supply costs, net of the margin on wholesale sales and sales of fuel, and the amount included in base retail rates for Washington customers. In the 2010 Washington general rate case settlement, the parties agreed that there would be no deferrals under the ERM for 2010. Deferrals under the ERM resumed in 2011. Total net deferred power costs under the ERM were a liability of $22.2 million as of December 31, 2012, and this balance represents the customer portion of the deferred power costs. As part of the approved Washington general rate case settlement filed on October 19, 2012 and approved on December 26, 2012, during 2013 a one-year credit of $4.4 million would be returned to electric customers from the existing ERM deferral balance so the net average electric rate increase to customers in 2013 would be 2.0 percent. Additionally, during 2014 a one-year credit of $9.0 million would be returned to electric customers from the then-existing ERM deferral balance, if such funds are available, so the net average electric rate increase to customers effective January 1, 2014 would be 2.0 percent. The credits to customers from the ERM balances would not impact the Company's net income.

Under the ERM, the Company absorbs the cost or receives the benefit from the initial amount of power supply costs in excess of or below the level in retail rates, which is referred to as the deadband. The annual (calendar year) deadband amount is currently $4.0 million. The Company will incur the cost of, or receive the benefit from, 100 percent of this initial power supply cost variance. The Company shares annual power supply cost variances between $4.0 million and $10.0 million with its 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, 90 percent of the cost variance is deferred for future surcharge or rebate. The Company absorbs or receives the benefit in power supply costs of the remaining 10 percent of the annual variance beyond $10.0 million without affecting current or future customer rates.

The following is a summary of the ERM:

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

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

Avista Corp. has a Power Cost Adjustment (PCA) mechanism in Idaho that allows it to modify electric rates on October 1 of each year with Idaho Public Utilities Commission (IPUC) approval. Under the PCA mechanism, Avista Corp. defers 90 percent of the difference between certain actual net power supply expenses and the amount included in base retail rates for its Idaho customers. These annual

October 1 rate adjustments recover or rebate power costs deferred during the preceding July-June twelve-month period. Total net power supply costs deferred under the PCA mechanism were a regulatory liability of $5.1 million as of December 31, 2012 and $0.7 million as of December 31, 2011.

Natural Gas Cost Deferrals and Recovery Mechanisms

Avista Corp. files a purchased gas cost adjustment (PGA) in all three states it serves to adjust natural gas rates for: 1) estimated commodity and pipeline transportation costs to serve natural gas customers for the coming year, and 2) the difference between actual and estimated commodity and transportation costs for the prior year. These annual PGA filings in Washington and Idaho provide for the deferral, and recovery or refund, of 100 percent of the difference between actual and estimated commodity and pipeline transportation costs, subject to applicable regulatory review. The annual PGA filing in Oregon provides for deferral, and recovery or refund, of 100 percent of the difference between actual and estimated pipeline transportation costs and commodity costs that are fixed through hedge transactions. Commodity costs that are not hedged for Oregon customers are subject to a sharing mechanism whereby Avista Corp. defers, and recovers or refunds, 90 percent of the difference between these actual and estimated costs. Total net deferred natural gas costs to be refunded to customers were a liability of $6.9 million as of December 31, 2012 and $12.1 million as of December 31, 2011.

Washington General Rate Cases

In December 2011, the UTC approved a settlement agreement in the Company's electric and natural gas general rate cases filed in May 2011. As agreed to in the settlement agreement, base electric rates for the Company's Washington customers increased by an average of 4.6 percent, which is designed to increase annual revenues by $20.0 million. Base natural gas rates for the Company's Washington customers increased by an average of 2.4 percent, which is designed to increase annual revenues by $3.75 million. The new electric and natural gas rates became effective on January 1, 2012.

As part of the settlement agreement, the Company agreed to not file a general rate case in Washington prior to April 1, 2012.

The settlement agreement also provides for the deferral of certain generation plant maintenance costs. In order to address the variability in year-to-year maintenance costs, beginning in 2011, the Company is deferring changes in maintenance costs related to its Coyote Spring 2 natural gas-fired generation plant and its 15 percent ownership interest in Units 3 & 4 of the Colstrip generation plant. The Company compares actual, non-fuel, maintenance expenses for the Coyote Springs 2 and Colstrip plants with the amount of baseline maintenance expenses used to establish base retail rates, and defers the difference. The deferral occurred annually, with no carrying charge, with deferred costs being amortized over a four-year period, beginning in January of the year following the period costs are deferred. The amount of expense to be requested for recovery in future general rate cases would be the actual maintenance expense recorded in the test period, less any amount deferred during the test period, plus the amortization of previously deferred costs. Total net deferred costs under this mechanism in Washington were a regulatory asset of $4.0 million as of December 31, 2012 compared to a regulatory liability of $0.5 million as of December 31, 2011.

As part of the settlement agreement in October 2012 to the Company's latest general rate case discussed in further detail below, the parties have agreed that the maintenance cost deferral mechanism on these generation plants will terminate on December 31, 2012, with the four-year amortization of the 2011 and 2012 deferrals to conclude in 2015 and 2016, respectively.

In December 2012, the UTC approved a settlement agreement in the Company's electric and natural gas general rate cases filed in April 2012. As agreed to in the settlement, effective January 1, 2013, 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). The settling parties agree that a one-year credit of $4.4 million will be returned to electric customers from the existing ERM deferral balance so the net average electric rate increase impact to the Company's customers in 2013 will be 2.0 percent. The credit to customers from the ERM balance will not impact the Company's earnings.

The settlement also provided that, effective January 1, 2014, the Company will implement temporary base rate increases 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 settling parties agree that a one-year credit of $9.0 million will be returned to electric customers from the then-existing ERM deferral balance, if such funds are available, so the net average electric rate increase to customers effective January 1, 2014 would be 2.0 percent. The credit to customers from the ERM balance will not impact the Company's earnings.

The UTC order approving the settlement agreement included certain conditions. The new retail rates to become effective January 1, 2014 will be temporary rates, and on January 1, 2015 electric and natural gas base rates will revert back to 2013 levels absent any intervening action from the UTC. The settlement agreement also states that the Company will not file a general rate case in Washington that would cause an increase in base retail rates before January 1, 2015. The Company could, however, make a filing prior to January 2015, but new rates resulting from the filing would not take effect prior to January 1, 2015. This does not preclude the Company from filing annual rate adjustments such as the PGA.

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

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

Idaho General Rate Cases

In September 2011, the IPUC approved a settlement agreement in the Company's general rate case filed in July 2011. The new electric and natural gas rates became effective on October 1, 2011. As agreed to in the settlement agreement, base electric rates for the Company's Idaho customers increased by an average of 1.1 percent, which was designed to increase annual revenues by $2.8 million. Base natural gas rates for the Company's Idaho customers increased by an average of 1.6 percent, which was designed to increase annual revenues by $1.1 million.

As part of the settlement agreement, the Company agreed to not seek to make effective a change in base electric or natural gas rates prior to April 1, 2013, by means of a general rate case filing. This does not preclude the Company from filing annual rate adjustments such as the PCA and the PGA.

The settlement agreement also provides for the deferral of certain generation plant operation and maintenance costs. In order to address the variability in year-to-year operation and maintenance costs, beginning in 2011, the Company is deferring changes in operation and maintenance costs related to the Coyote Spring 2 natural gas-fired generation plant and its 15 percent ownership interest in Units 3 & 4 of the Colstrip generation plant. The Company compares actual, non-fuel, operation and maintenance expenses for the Coyote Springs 2 and Colstrip plants with the amount of expenses authorized for recovery in base rates in the applicable deferral year, and defers the difference from that currently authorized. The deferral occurs annually, with no carrying charge, with deferred costs being amortized over a three-year period, beginning in January of the year following the period costs are deferred. The amount of expense to be requested for recovery in future general rate cases will be the actual operation and maintenance expense recorded in the test period, less any amount deferred during the test period, plus the amortization of previously deferred costs. Total net deferred costs under this mechanism in Idaho were regulatory assets of $2.3 million as of December 31, 2012 and $0.1 million as of December 31, 2011.

On October 11, 2012, the Company filed electric and natural gas general rate cases with the IPUC. The Company requested an overall increase in electric rates of 4.6 percent and an overall increase in natural gas rates of 7.2 percent. The filings were designed to increase annual electric revenues by $11.4 million and increase annual natural gas revenues by $4.6 million. The Company's requests were based on a proposed overall rate of return of 8.46 percent, with a common equity ratio of 50 percent and a 10.9 percent return on equity.

On February 6, 2013, Avista Corp. and certain other parties filed a settlement agreement with the IPUC with respect to Avista Corp.'s electric and natural gas general rate cases. Parties to the settlement agreement include the staff of the IPUC, Clearwater Paper Corporation, Idaho Forest Group, LLC, the Idaho Conservation League, and the Company. Community Action Partnership Association of Idaho (CAPAI), a low-income customer advocacy group, and the Snake River Alliance did not join in the settlement agreement. However, on February 20, 2013 the Snake River Alliance provided a letter to the IPUC supporting the settlement agreement. This settlement agreement is subject to approval by the IPUC and would conclude the proceedings related the general rate requests filed by the Company on October 11, 2012. New rates would be implemented in two phases: April 1, 2013 and October 1, 2013.

The settlement agreement proposes that, effective April 1, 2013, Avista Corp. would be authorized to implement a base rate increase for Idaho natural gas customers of 4.9 percent (designed to increase annual revenues by $3.1 million). There would be no change in base electric rates on April 1, 2013. However, the settlement agreement would provide for the recovery of the costs of the Palouse Wind Project through the Power Cost Adjustment mechanism beginning April 1, 2013.

The settlement agreement also proposes that, effective October 1, 2013, Avista Corp. would be authorized to implement a base rate increase for Idaho natural gas customers of 2.0 percent (designed to increase annual revenues by $1.3 million). A credit resulting from deferred natural gas costs of $1.6 million would be 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 would be 0.3 percent.

Further, the settlement proposes that, effective October 1, 2013, Avista Corp. would be authorized to implement a base rate increase for Idaho electric customers of 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 would be 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 would be 1.9 percent.

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

Also included in the settlement agreement is a provision that Avista Corp. may file a general rate case in Idaho in 2014; however, new rates resulting from the filing would not take effect prior to January 1, 2015.

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

The settlement also includes an after-the-fact earnings test for 2013 and 2014, such that if Avista Corp., on a consolidated basis for electric and natural gas operations in Idaho, earns more than a 9.8 percent return on equity, Avista Corp. would refund to customers 50 percent of any earnings above the 9.8 percent.

Oregon General Rate Cases

In March 2011, the OPUC approved an all-party settlement stipulation in the Company's general rate case that was filed in September 2010. The settlement provides for an overall rate increase of 3.1 percent for the Company's Oregon customers, designed to increase annual revenues by $3.0 million. Part of the rate increase became effective March 15, 2011, with the remaining increase effective June 1, 2011. An additional rate adjustment designed to increase revenues by $0.6 million will occur on June 1, 2012 to recover capital costs associated with certain reinforcement and replacement projects upon a demonstration that such projects are complete and the costs were prudently incurred.

On January 1, 2013, Avista Corp. purchased the Klamath Falls Lateral (Lateral), a 15-mile, 6-inch natural gas transmission pipeline from Williams Northwest Pipeline (Williams). The Klamath Falls Lateral interconnects with another interstate pipeline, Gas Transmission Northwest, to transport natural gas to serve Avista Corp.'s customers in Klamath Falls, Oregon. The purchase price was approximately $2.3 million and will save Oregon customers approximately $1.4 million annually as Avista Corp. will be able to reduce its contracted natural gas transportation requirements from Williams. In Order No. 12-429, the OPUC approved the Company's request to recover from customers the revenue requirement associated with the purchase of the Lateral, which is approximately $0.5 million annually. This approval will provide a return of and a return on Avista Corp.'s investment in the lateral. While the OPUC approved the recovery of the revenue requirement, it will not determine whether the purchase of the Lateral was prudent until the Company's next Oregon general rate case.

NOTE 21. SUPPLEMENTAL CASH FLOW INFORMATION (in thousands)

	2012	2011
Cash paid for interest	$68,508	$63,876
Cash paid for income taxes	$6,631	$16,631

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Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

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

Line No.	Item (a)	Total Company For the Current Quarter/Year
1	UTILITY PLANT	
2	In Service	
3	Plant in Service (Classified)	4,032,753,210
4	Property Under Capital Leases	6,442,349
5	Plant Purchased or Sold	
6	Completed Construction not Classified	
7	Experimental Plant Unclassified	
8	TOTAL Utility Plant (Total of lines 3 thru 7)	4,039,195,559
9	Leased to Others	
10	Held for Future Use	4,989,371
11	Construction Work in Progress	139,513,892
12	Acquisition Adjustments	
13	TOTAL Utility Plant (Total of lines 8 thru 12)	4,183,698,822
14	Accumulated Provisions for Depreciation, Amortization, & Depletion	1,408,153,972
15	Net Utility Plant (Total of lines 13 and 14)	2,775,544,850
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION	
17	In Service:	
18	Depreciation	(1,375,661,340)
19	Amortization and Depletion of Producing Natural Gas Land and Land Rights	
20	Amortization of Underground Storage Land and Land Rights	
21	Amortization of Other Utility Plant	(32,492,632)
22	TOTAL In Service (Total of lines 18 thru 21)	(1,408,153,972)
23	Leased to Others	
24	Depreciation	
25	Amortization and Depletion	
26	TOTAL Leased to Others (Total of lines 24 and 25)	
27	Held for Future Use	
28	Depreciation	
29	Amortization	
30	TOTAL Held for Future Use (Total of lines 28 and 29)	
31	Abandonment of Leases (Natural Gas)	
32	Amortization of Plant Acquisition Adjustment	
33	TOTAL Accum. Provisions (Should agree with line 14 above)(Total of lines 22, 26, 30, 31, and 32)	(1,408,153,972)

Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

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

Line No.	Electric (c)	Gas (d)	Other (specify) (e)	Common (f)
1				
2				
3	3,033,013,660	777,111,351		222,628,199
4		858,865		5,583,484
5				
6				
7				
8	3,033,013,660	777,970,216		228,211,683
9				
10	4,773,791	215,580		
11	80,205,686	18,296,122		41,012,084
12				
13	3,117,993,137	796,481,918		269,223,767
14	1,075,820,044	269,742,833		62,591,095
15	2,042,173,093	526,739,085		206,632,672
16				
17				
18	(1,065,032,018)	(268,498,775)		(42,130,547)
19				
20				
21	(10,788,026)	(1,244,059)		(20,460,547)
22	(1,075,820,044)	(269,742,834)		(62,591,094)
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33	(1,075,820,044)	(269,742,834)		(62,591,094)

Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

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

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

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)
1	INTANGIBLE PLANT		
2	301 Organization		
3	302 Franchises and Consents		
4	303 Miscellaneous Intangible Plant	3,172,476	627,074
5	TOTAL Intangible Plant (Enter Total of lines 2 thru 4)	3,172,476	627,074
6	PRODUCTION PLANT		
7	Natural Gas Production and Gathering Plant		
8	325.1 Producing Lands		
9	325.2 Producing Leaseholds		
10	325.3 Gas Rights		
11	325.4 Rights-of-Way		
12	325.5 Other Land and Land Rights		
13	326 Gas Well Structures		
14	327 Field Compressor Station Structures		
15	328 Field Measuring and Regulating Station Equipment		
16	329 Other Structures		
17	330 Producing Gas Wells-Well Construction		
18	331 Producing Gas Wells-Well Equipment		
19	332 Field Lines		
20	333 Field Compressor Station Equipment		
21	334 Field Measuring and Regulating Station Equipment		
22	335 Drilling and Cleaning Equipment		
23	336 Purification Equipment		
24	337 Other Equipment		
25	338 Unsuccessful Exploration and Development Costs		
26	339 Asset Retirement Costs for Natural Gas Production and		
27	TOTAL Production and Gathering Plant (Enter Total of lines 8		
28	PRODUCTS EXTRACTION PLANT		
29	340 Land and Land Rights		
30	341 Structures and Improvements		
31	342 Extraction and Refining Equipment		
32	343 Pipe Lines		
33	344 Extracted Products Storage Equipment		

Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

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

including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Account 101 and 106 will avoid serious omissions of respondent's reported amount for plant actually in service at end of year.

6. 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. In showing the clearance of Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits to primary account classifications.

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

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

Line No.	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
1				
2				
3				
4	54,251			3,745,299
5	54,251			3,745,299
6				
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Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

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

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)
34	345 Compressor Equipment		
35	346 Gas Measuring and Regulating Equipment		
36	347 Other Equipment		
37	348 Asset Retirement Costs for Products Extraction Plant		
38	TOTAL Products Extraction Plant (Enter Total of lines 29 thru 37)		
39	TOTAL Natural Gas Production Plant (Enter Total of lines 27 and		
40	Manufactured Gas Production Plant (Submit Supplementary	7,628	
41	TOTAL Production Plant (Enter Total of lines 39 and 40)	7,628	
42	NATURAL GAS STORAGE AND PROCESSING PLANT		
43	Underground Storage Plant		
44	350.1 Land	407,111	
45	350.2 Rights-of-Way	59,812	
46	351 Structures and Improvements	1,366,042	89,810
47	352 Wells	13,470,575	(17,524)
48	352.1 Storage Leaseholds and Rights	254,354	
49	352.2 Reservoirs	1,667,492	
50	352.3 Non-recoverable Natural Gas	5,810,311	
51	353 Lines	1,106,781	
52	354 Compressor Station Equipment	14,221,273	270,042
53	355 Other Equipment	173,784	120,765
54	356 Purification Equipment	407,617	
55	357 Other Equipment	1,485,146	84,367
56	358 Asset Retirement Costs for Underground Storage Plant		
57	TOTAL Underground Storage Plant (Enter Total of lines 44 thru	40,430,298	547,460
58	Other Storage Plant		
59	360 Land and Land Rights		
60	361 Structures and Improvements		
61	362 Gas Holders		
62	363 Purification Equipment		
63	363.1 Liquefaction Equipment		
64	363.2 Vaporizing Equipment		
65	363.3 Compressor Equipment		
66	363.4 Measuring and Regulating Equipment		
67	363.5 Other Equipment		
68	363.6 Asset Retirement Costs for Other Storage Plant		
69	TOTAL Other Storage Plant (Enter Total of lines 58 thru 68)		
70	Base Load Liquefied Natural Gas Terminaling and Processing Plant		
71	364.1 Land and Land Rights		
72	364.2 Structures and Improvements		
73	364.3 LNG Processing Terminal Equipment		
74	364.4 LNG Transportation Equipment		
75	364.5 Measuring and Regulating Equipment		
76	364.6 Compressor Station Equipment		
77	364.7 Communications Equipment		
78	364.8 Other Equipment		
79	364.9 Asset Retirement Costs for Base Load Liquefied Natural Gas		
80	TOTAL Base Load Liquefied Nat'l Gas, Terminaling and		

Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

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

Line No.	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
34				
35				
36				
37				
38				
39				
40				7,628
41				7,628
42				
43				
44				407,111
45				59,812
46				1,455,852
47				13,453,051
48				254,354
49				1,667,492
50				5,810,311
51				1,106,781
52	63,794			14,427,521
53			(19,819)	274,730
54			(3,905)	403,712
55				1,569,513
56				
57	63,794		(23,724)	40,890,240
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Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

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

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)
81	TOTAL Nat'l Gas Storage and Processing Plant (Total of lines 57,	40,430,298	547,460
82	TRANSMISSION PLAN		
83	365.1 Land and Land Rights		
84	365.2 Rights-of-Way		
85	366 Structures and Improvements		
86	367 Mains		
87	368 Compressor Station Equipment		
88	369 Measuring and Regulating Station Equipment		
89	370 Communication Equipment		
90	371 Other Equipment		
91	372 Asset Retirement Costs for Transmission Plant		
92	TOTAL Transmission Plant (Enter Totals of lines 83 thru 91)		
93	DISTRIBUTION PLANT		
94	374 Land and Land Rights	267,688	
95	375 Structures and Improvements	1,070,308	55,108
96	376 Mains	362,516,823	11,417,728
97	377 Compressor Station Equipment		
98	378 Measuring and Regulating Station Equipment-General	9,020,760	333,061
99	379 Measuring and Regulating Station Equipment-City Gate	7,414,781	134,723
100	380 Services	202,206,046	6,636,204
101	381 Meters	97,189,594	5,453,681
102	382 Meter Installations		
103	383 House Regulators		
104	384 House Regulator Installations		
105	385 Industrial Measuring and Regulating Station Equipment	4,045,449	229,675
106	386 Other Property on Customers' Premises		
107	387 Other Equipment	539	
108	388 Asset Retirement Costs for Distribution Plant		
109	TOTAL Distribution Plant (Enter Total of lines 94 thru 108)	683,731,988	24,260,180
110	GENERAL PLANT		
111	389 Land and Land Rights	949,240	
112	390 Structures and Improvements	5,193,175	150,451
113	391 Office Furniture and Equipment	429,445	47,380
114	392 Transportation Equipment	9,171,373	1,007,736
115	393 Stores Equipment	141,498	
116	394 Tools, Shop, and Garage Equipment	3,875,874	504,165
117	395 Laboratory Equipment	480,676	
118	396 Power Operated Equipment	3,964,851	560,606
119	397 Communication Equipment	2,899,266	133,487
120	398 Miscellaneous Equipment	2,367	
121	Subtotal (Enter Total of lines 111 thru 120)	27,107,765	2,403,825
122	399 Other Tangible Property		
123	399.1 Asset Retirement Costs for General Plant		
124	TOTAL General Plant (Enter Total of lines 121, 122 and 123)	27,107,765	2,403,825
125	TOTAL (Accounts 101 and 106)	754,450,155	27,838,539
126	Gas Plant Purchased (See Instruction 8)		
127	(Less) Gas Plant Sold (See Instruction 8)		
128	Experimental Gas Plant Unclassified		
129	TOTAL Gas Plant In Service (Enter Total of lines 125 thru 128)	754,450,155	27,838,539

Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

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

Line No.	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)
81	63,794		(23,724)	40,890,240
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93				
94				267,688
95	636			1,124,780
96	594,414			373,340,137
97				
98	42,957			9,310,864
99	31,195			7,518,309
100	343,250			208,499,000
101	2,356,541			100,286,734
102				
103				
104				
105				4,275,124
106				
107				539
108				
109	3,368,993			704,623,175
110				
111				949,240
112	15,391			5,328,235
113				476,825
114	324,728			9,854,381
115				141,498
116	72,683			4,307,356
117	74,044			406,632
118	295,498			4,229,959
119	25,372			3,007,381
120				2,367
121	807,716			28,703,874
122				
123				
124	807,716			28,703,874
125	4,294,754		(23,724)	777,970,216
126				
127				
128				
129	4,294,754		(23,724)	777,970,216

Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

Gas Plant Held for Future Use (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $1,000,000 or more. Group other items of property held for future use.
2. For property having an original cost of $1,000,000 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	Gas Distribution Mains and Services	03/01/2007		184,818
2	located in Coeur d'Alene, Idaho			
3	Gas Distribution Mains and Services	07/01/2011		30,762
4	located in Coeur d'Alene, Idaho			
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45	**Total**	[redacted]		**215,580**

Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

Construction Work in Progress-Gas (Account 107)

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

Line No.	Description of Project (a)	Construction Work in Progress-Gas (Account 107) (b)	Estimated Additional Cost of Project (c)
1	Aldyl-A Pipe Replacement Project	4,456,690	53,410,000
2	Klamath Falls Lateral Project	2,525,019	
3	Gas Distribution Non-Revenue Blanket	2,351,146	186,744
4	Gas Revenue Blanket	2,126,113	12,848
5	Transportation Equipment Blanket	1,362,050	57,435
6	Gas Replace - Street & Highway Blanket	1,222,007	1,012,920
7	Minor Projects under $1,000,000	4,253,097	4,160,944
8			
9	Notes:		
10	(1) Aldyl-A replacement Estimated Additional Cost		
11	amount represents a 5 year budget total.		
12	(2) Blankets are an accumulation of many projects. The		
13	Estimated Additional Costs represent expected spend on		
14	projects open at year end.		
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45	**Total**	**18,296,122**	**58,840,891**

Name of Respondent	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report 2012/Q4

General Description of Construction Overhead Procedure

1. For each construction overhead explain: (a) the nature and extent of work, etc., the overhead charges are intended to cover, (b) the general procedure for determining the amount capitalized, (c) the method of distribution to construction jobs, (d) whether different rates are applied to different types of construction, (e) basis of differentiation in rates for different types of construction, and (f) whether the overhead is directly or indirectly assigned.
2. Show below the computation of allowance for funds used during construction rates, in accordance with the provisions of Gas Plant Instructions 3 (17) of the Uniform System of Accounts.
3. Where a net-of-tax rate for borrowed funds is used, show the appropriate tax effect adjustment to the computations below in a manner that clearly indicates the amount of reduction in the gross rate for tax effects.

Construction costs with a direct relationship to new construction and capital replacement activities that cannot be clearly identified with specific projects are charged to overhead pools. The established pools are:

- Construction Overhead North Gas
- Construction Overhead South Gas

Pool costs are allocated monthly to gas construction projects on a percent rate applied to direct project costs, excluding AFUDC. Each pool's rate is calculated separately and applied only to the related gas construction projects for allocation.

Allowance for funds used during construction (AFUDC) is calculated system-wide using a rate that is equivalent to the allowed rate of return approved in the latest rate order from the company's primary state commission (Washington State). For 2012, Avista used a rate of 7.62% which is the allowed rate of return contained in the Washington Utilties and Transportation Commission Final Order 06 dated December 16, 2011, for consolidated Dockets UE-110876 and UG-110877.

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General Description of Construction Overhead Procedure (continued)

COMPUTATION OF ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION RATES

1. For line (5), column (d) below, enter the rate granted in the last rate proceeding. If not available, use the average rate earned during the preceding 3 years.
2. Identify, in a footnote, the specific entity used as the source for the capital structure figures.
3. Indicate, in a footnote, if the reported rate of return is one that has been approved in a rate case, black-box settlement rate, or an actual three-year average rate.

1. Components of Formula (Derived from actual book balances and actual cost rates):

Line No.	Title (a)	Amount (b)	Capitalization Ration (percent) (c)	Cost Rate Percentage (d)
	(1) Average Short-Term Debt	S		
	(2) Short-Term Interest			s
	(3) Long-Term Debt	D		d
	(4) Preferred Stock	P		p
	(5) Common Equity	C		c
	(6) Total Capitalization			
	(7) Average Construction Work In Progress Balance	W		

2. Gross Rate for Borrowed Funds s(S/W) + d[(D/(D+P+C)) (1-(S/W))]

3. Rate for Other Funds [1-(S/W)] [p(P/(D+P+C)) + c(C/(D+P+C))]

4. Weighted Average Rate Actually Used for the Year:

a. Rate for Borrowed Funds - 3.06

b. Rate for Other Funds - 4.56

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Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

Accumulated Provision for Depreciation of Gas 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 10, column (c), and that reported for gas plant in service, page 204-209, column (d), excluding retirements of nondepreciable 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.
5. At lines 7 and 14, add rows as necessary to report all data. Additional rows should be numbered in sequence, e.g., 7.01, 7.02, etc.

Line No.	Item (a)	Total (c+d+e) (b)	Gas Plant in Service (c)	Gas Plant Held for Future Use (d)	Gas Plant Leased to Others (e)
	Section A. BALANCES AND CHANGES DURING YEAR				
1	Balance Beginning of Year	256,805,795	256,805,795		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	15,965,536	15,965,536		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Expense of Gas Plant Leased to Others				
6	Transportation Expenses - Clearing	276,862	276,862		
7	Other Clearing Accounts				
8	Other Clearing (Specify) (footnote details):				
9					
10	TOTAL Deprec. Prov. for Year (Total of lines 3 thru 8)	16,242,398	16,242,398		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	(4,247,572)	(4,247,572)		
13	Cost of Removal	295,612	295,612		
14	Salvage (Credit)	(9,676)	(9,676)		
15	TOTAL Net Chrgs for Plant Ret. (Total of lines 12 thru 14)	(3,942,284)	(3,942,284)		
16	Other Debit or Credit Items (Describe) (footnote details):	(607,135)	(607,135)		
17					
18	Book Cost of Asset Retirement Costs				
19	Balance End of Year (Total of lines 1,10,15,16 and 18)	268,498,774	268,498,774		
	Section B. BALANCES AT END OF YEAR ACCORDING TO FUNCTIONAL CLASSIFICATIONS				
21	Productions-Manufactured Gas				
22	Production and Gathering-Natural Gas				
23	Products Extraction-Natural Gas				
24	Underground Gas Storage	12,870,672	12,870,672		
25	Other Storage Plant				
26	Base Load LNG Terminaling and Processing Plant				
27	Transmission				
28	Distribution	246,429,510	246,429,510		
29	General	9,198,592	9,198,592		
30	TOTAL (Total of lines 21 thru 29)	268,498,774	268,498,774		

Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

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

1. If during the year adjustments were made to the stored gas inventory reported in columns (d), (f), (g), and (h) (such as to correct cumulative inaccuracies of gas measurements), explain in a footnote the reason for the adjustments, the Dth and dollar amount of adjustment, and account charged or credited.
2. Report in column (e) all encroachments during the year upon the volumes designated as base gas, column (b), and system balancing gas, column (c), and gas property recordable in the plant accounts.
3. State in a footnote the basis of segregation of inventory between current and noncurrent portions. Also, state in a footnote the method used to report storage (i.e., fixed asset method or inventory method).

Line No.	Description (a)	(Account 117.1) (b)	(Account 117.2) (c)	Noncurrent (Account 117.3) (d)	(Account 117.4) (e)	Current (Account 164.1) (f)	LNG (Account 164.2) (g)	LNG (Account 164.3) (h)	Total (i)
1	Balance at Beginning of	6,992,076				23,609,470			30,601,546
2	Gas Delivered to Storage					23,177,606			23,177,606
3	Gas Withdrawn from					29,510,789			29,510,789
4	Other Debits and Credits								
5	Balance at End of Year	6,992,076				17,276,287			24,268,363
6	Dth	1,253,060				7,463,643			8,716,703
7	Amount Per Dth	5.5800				2.3147			2.7841

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Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

Investments (Account 123, 124, and 136)

1. Report below investments in Accounts 123, Investments in Associated Companies, 124, Other Investments, and 136, Temporary Cash Investments.
2. Provide a subheading for each account and list thereunder the information called for:
(a) Investment in Securities-List and describe each security owned, giving name of issuer, date acquired and date of maturity. For bonds, also give principal amount, date of issue, maturity, and interest rate. For capital stock (including capital stock of respondent reacquired under a definite plan for resale pursuant to authorization by the Board of Directors, and included in Account 124, Other Investments) state number of shares, class, and series of stock. Minor investments may be grouped by classes. Investments included in Account 136, Temporary Cash Investments, also may be grouped by classes.
(b) Investment Advances-Report separately for each person or company the amounts of loans or investment advances that are properly includable in Account 123. Include advances subject to current repayment in Account 145 and 146. With respect to each advance, show whether the advance is a note or open account.

Line No.	Description of Investment (a)	* (b)	Book Cost at Beginning of Year (If book cost is different from cost to respondent, give cost to respondent in a footnote and explain difference) (c)	Purchases or Additions During the Year (d)
1	Investment in Spokane Energy (123000)		500,000	
2	Investment in Avista Capital II (123010)		11,547,000	
3	Other Investment - WZN Loans Sandpoint (124350)		61,177	
4	Other Investment - Coli Cash Value (124600)		13,293,355	
5	Other Investment - Coli Borrowings (124610)		(13,293,355)	
6	Other Investment - WZN Loans Oregon (124680)		45,031	
7	Other Investment - WNP3 Exchange Power (124900)		79,626,000	
8	Other Investment - AMT WNP3 Exchange (124930)		(60,842,823)	
9	Temp Cash Investments (136000)		60,913	
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Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

Investments (Account 123, 124, and 136) (continued)

List each note, giving date of issuance, maturity date, and specifying whether note is a renewal. Designate any advances due from officers, directors, stockholders, or employees.

3. Designate with an asterisk in column (b) any securities, notes or accounts that were pledged, and in a footnote state the name of pledges and purpose of the pledge.
4. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and cite Commission, date of authorization, and case or docket number.
5. Report in column (h) interest and dividend revenues from investments including such revenues from securities disposed of during the year.
6. In column (i) report for each investment disposed of during the year the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost) and the selling price thereof, not including any dividend or interest adjustment includible in column (h).

Line No.	Sales or Other Dispositions During Year (e)	Principal Amount or No. of Shares at End of Year (f)	Book Cost at End of Year (If book cost is different from cost to respondent, give cost to respondent in a footnote and explain difference) (g)	Revenues for Year (h)	Gain or Loss from Investment Disposed of (i)
1			500,000		
2			11,547,000		
3			61,177		
4	(1,383,948)		14,677,303		
5	1,383,948		(14,677,303)		
6	299		44,732		
7			79,626,000		
8	2,450,031		(63,292,854)		
9	(190,477)		251,390		
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Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

Investments in Subsidiary Companies (Account 123.1)

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

Line No.	Description of Investment (a)	Date Acquired (b)	Date of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	Avista Capital - Common Stock	01/01/1997		170,053,827
2	Avista Capital - Equity in Earnings			(101,447,380)
3	OCI Investment in Subs			134,045
4	Avista Capital - Other Changes in Net Investment			3,230,876
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40	**TOTAL Cost of Account 123.1 $**		**TOTAL**	71,971,368

Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

Investments in Subsidiary Companies (Account 123.1) (continued)

4. Designate in a footnote, any securities, notes, or accounts that were pledged, 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 in column (f) interest and dividend revenues from investments, including such revenues from securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if different from cost), and the selling price thereof, not including interest adjustments includible in column (f).
8. Report on Line 40, column (a) the total cost of Account 123.1.

Line No.	Equity in Subsidiary Earnings for Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)
1		(46,675,006)	216,728,833	
2	(1,206,861)		(102,654,241)	
3		(33,216)	167,261	
4		(1,241,694)	4,472,570	
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40	(1,206,861)	(47,949,916)	118,714,423	

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

PREPAYMENTS (ACCOUNT 165)

1. Report below the particulars (details) on each prepayment.

Line No.	Nature of Payment (a)	Balance at End of Year (in dollars) (b)
1	Prepaid Insurance	2,490,855
2	Prepaid Rents	
3	Prepaid Taxes	
4	Prepaid Interest	
5	Miscellaneous Prepayments	13,599,625
6	TOTAL	16,090,480

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Other Regulatory Assets (Account 182.3)

1. Report below the details called for concerning other regulatory assets which are created through the ratemaking actions of regulatory agencies (and not includable in other accounts).
2. For regulatory assets being amortized, show period of amortization in column (a).
3. Minor items (5% of the Balance at End of Year for Account 182.3 or amounts less than $250,000, whichever is less) may be grouped by classes.
4. Report separately any "Deferred Regulatory Commission Expenses" that are also reported on pages 350-351, Regulatory Commission Expenses.
5. Provide in a footnote, for each line item, the regulatory citation where authorization for the regulatory asset has been granted (e.g. Commission Order, state commission order, court decision).

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning Current Quarter/Year (b)	Debits (c)	Written off During Quarter/Year Account Charged (d)	Written off During Period Amount Recovered (e)	Written off During Period Amount Deemed Unrecoverable (f)	Balance at End of Current Quarter/Year (g)
1	Regulatory Asset FAS 106	472,752			472,752		
2	Guaranteed Residual Value-Airplane						
3	Reg Asset Post Ret Liab	260,358,633	46,049,036				306,407,669
4	Reg Asset FAS 109 Utility Plant	70,616,515			5,151,910		65,464,605
5	Reg Asset FAS 109 DSIT Non Plant	1,762,314			97,548		1,664,766
6	Reg Asset FAS 109 DSIT State Tax cr	6,669,689	794,495				7,464,184
7	Reg Asset FAS 109 WNP3	5,653,819			737,482		4,916,337
8	Reg Asset-Spokane River Relicense	701,098			78,736		622,362
9	Reg Asset-Spokane River PM&E	649,198			73,312		575,886
10	Reg Asset-Lake CDA Fund	9,648,664			211,065		9,437,599
11	Reg Asset- Decouplings Surcharge	190,282			182,958		7,324
12	Regulatory Asset AMR	70,934			70,934		
13	Reg Asset RTO Deposits ID						
14	Reg Asset BPA Residental Exchange	104,636	436,169				540,805
15	Reg Asset ERM Approved for Recovery						
16	ID Wind Gen AFUDC	358,264	11,109				369,373
17	Reg Asset Wartsilla Units	1,089,605			337,788		751,817
18	MTM St Regulatory Asset	69,684,643			34,603,118		35,081,525
19	Reg Asset- FAS 143 Asset Retirement Obligation	2,717,489			318,644		2,398,845
20	Reg Asset AN CDA Lake Settlement	39,186,540			1,559,332		37,627,208
21	Reg Asset WA CDA Lake Settlement	1,356,388			152,118		1,204,270
22	Reg Asset Workers Comp	2,623,100			344,422		2,278,678
23	CS2 Lev Ret	1,250,099			340,600		909,499
24	Reg Asset ID PCA Deferral 1						
25	Reg Asset ID PCA Deferral 2	2,017,929			2,017,929		
26	Reg Asset ID PCA Deferral 3	(2,762,169)	2,762,168				(1)
27	Reg Asset- Future Payments Lake CDA						
28	DSM Asset	798,418	2,578,599		798,418		2,578,599
29	Lancaster Generation	5,326,667			1,360,000		3,966,667
30	CDA Fund	2,000,000					2,000,000
31	MTM LT Reg Asset	40,345,338			15,127,641		25,217,697
32	Roseburg/Medford	142,470	122,541				265,011
33	CNC Trransmission	735,906			252,637		483,269
34	CS2 & Colstrip	143,226	6,685,420		516,251		6,312,395
35	LIdar O&M	337,879	249,379				587,258
36	SWAPS on FMBS		40,697,807				40,697,807
37							
38							
39							
40	**Total**	524,250,326	100,386,723		64,805,595	0	559,831,454

Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

Miscellaneous Deferred Debits (Account 186)

1. Report below the details called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a).
3. Minor items (less than $250,000) 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				1,110,999
3	Regulatory Asset-Decoupling def	(19,852)	19,852			
4						
5	Regulatory Asset-Mt lease pymt	1,713,249		540	360,684	1,352,565
6	Regulatory Asset-Mt lease pymt	3,383,112		540	676,632	2,706,480
7	Colstrip Common Fac.	2,355,642				2,355,642
8	Prepaid airplane Lease LT	466,025		931	147,166	318,859
9	Misc DD- Airplane lase cap	90,181	12,556			102,737
10	Plant allocation of clrg journal	1,140,273	2,444,223			3,584,496
11	Misc DD-IR Swaps	18,895,143		245	18,895,143	
12	Misc Error Suspense	5,225		var	342,205	(336,980)
13	Renewable Energy-Cert Fees	174,000		557	9,156	164,844
14	Nez Perce Settlement	165,961		557	5,212	160,749
15	Long Term Note Rec acct	209,469		143	204,050	5,419
16	Reg Asset ID-Lake Cda	271,030		506	30,974	240,056
17	Misc deffered debits/WA FRED DEF			var	277,010	(277,010)
18	ID Panhandle Forest Use Permit	181,017				181,017
19	Credit Union Labor & Exp	25,762	9,248			35,010
20	Outdoor Lghtng Greenbelt Pathwy	65,248	32,979			98,227
21	Horizon Wind Interco	61,845				61,845
22	Insurance Recv CDA Lake	320,932		var	320,932	
23	KF Water Rights Supply	1,179,357		310	1,178,588	769
24	Reclass Idaho Clk Fork Relic	452,846		537	265,896	186,950
25	Reclass misc def debits		357,784			357,784
26	Misc Work Orders <$50,000	(149,432)	275,641			126,209
27	Subsidiary Billings	42,452	135,814			178,266
28	"Null" Projects directly to 186	15,197				15,197
29	Conservation					
30	Regulatory Assets Consv	(200)	200			
31	Regulatory Assets Consv	1,845,898		var	185,185	1,660,713
32						
33	Optional Wind Power			909	186,231	(186,231)
34						
35						
36	Misc deffered debits/Res Acct		1,577,531			1,577,531
37	Deffered Palouse Wind %Thornton SW ST			557	80,774	(80,774)
38						
39	Miscellaneous Work in Progress					
40	**Total**	**34,001,379**	**4,865,828**		**23,165,838**	**15,701,369**

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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.
3. Provide in a footnote a summary of the type and amount of deferred income taxes reported in the beginning-of-year and end-of-year balances for deferred income taxes that the respondent estimates could be included in the development of jurisdictional recourse rates.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Changes During Year Amounts Debited to Account 410.1 (c)	Changes During Year Amounts Credited to Account 411.1 (d)
1	Account 190			
2	Electric	9,302,194		
3	Gas	1,056,689		
4	Other (Define) (footnote details)	143,049,537		
5	Total (Total of lines 2 thru 4)	153,408,420		
6	Other (Specify) (footnote details)			
7	TOTAL Account 190 (Total of lines 5 thru 6)	153,408,420		
8	Classification of TOTAL			
9	Federal Income Tax	153,408,420		
10	State Income Tax			
11	Local Income Tax			

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Accumulated Deferred Income Taxes (Account 190) (continued)

Line No.	Changes During Year Amounts Debited to Account 410.2 (e)	Changes During Year Amounts Credited to Account 411.2 (f)	Adjustments Debits Account No. (g)	Adjustments Debits Amount (h)	Adjustments Credits Account No. (i)	Adjustments Credits Amount (j)	Balance at End of Year (k)
1							
2				3,041,126			6,261,068
3						1,105,243	2,161,932
4				3,047,068			140,002,469
5				6,088,194		1,105,243	148,425,469
6							
7				6,088,194		1,105,243	148,425,469
8							
9				6,088,194		1,105,243	148,425,469
10							
11							

Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

Capital Stock (Accounts 201 and 204)

1. Report below the 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.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.
3. Give details concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.

Line No.	Class and Series of Stock and Name of Stock Exchange (a)	Number of Shares Authorized by Charter (b)	Par or Stated Value per Share (c)	Call Price at End of Year (d)
1	Acct. 201 - Common Stock Issued:			
2	No Par Value	200,000,000		
3	Restriced shares			
4	TOTAL Common	200,000,000		
5				
6				
7	Account 204 - Preferred Stock Issued	10,000,000		
8				
9	Total Preferred	10,000,000		
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Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

Capital Stock (Accounts 201 and 204)

4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or noncumulative.
5. State in a footnote if any capital stock that has been nominally issued is nominally outstanding at end of year.
6. Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purpose of pledge.

Line No.	Outstanding per Bal. Sheet (total amt outstanding without reduction for amts held by respondent) Shares (e)	Outstanding per Bal. Sheet Amount (f)	Held by Respondent As Reacquired Stock (Acct 217) Shares (g)	Held by Respondent As Reacquired Stock (Acct 217) Cost (h)	Held by Respondent In Sinking and Other Funds Shares (i)	Held by Respondent In Sinking and Other Funds Amount (j)
1						
2	59,812,796	863,316,222			117,118.00	3,025,158.00
3						
4	59,812,796	863,316,222			117,118.00	3,025,158.00
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Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

Other Paid-In Capital (Accounts 208-211)

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

(a) Donations Received from Stockholders (Account 208) - State amount and briefly explain the origin and purpose of each donation.

(b) Reduction in Par or Stated Value of Capital Stock (Account 209) - State amount and briefly explain the capital changes that gave rise to amounts reported under this caption including identification with the class and series of stock to which related.

(c) Gain or Resale or Cancellation of Reacquired Capital Stock (Account 210) - Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.

(d) Miscellaneous Paid-In Capital (Account 211) - Classify amounts included in this account according to captions that, together with brief explanations, disclose the general nature of the transactions that gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Equity transactions of subsidiaries	10,942,942
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40	**Total**	**10,942,942**

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Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

DISCOUNT ON CAPITAL STOCK (ACCOUNT 213)

1. Report the balance at end of year of discount on capital stock for each class and series of capital stock. Use as many rows as necessary to report all data.
2. If any change occurred during the year in the balance with respect to any class or series of stock, attach a statement giving details of the change. State the reason for any charge-off during the year and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
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13		
14		
	TOTAL	

CAPITAL STOCK EXPENSE (ACCOUNT 214)

1. Report the balance at end of year of capital stock expenses for each class and series of capital stock. Use as many rows as necessary to report all data. Number the rows in sequence starting from the last row number used for Discount on Capital Stock above.
2. If any change occurred during the year in the balance with respect to any class or series of stock, attach a statement giving 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)
16	Common Stock - No Par Value	(14,977,565)
17		
18		
19		
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27		
28		
	TOTAL	(14,977,565)

FOOTNOTE DATA

Schedule Page: 254 Line No.: 16 Column: b

Capital Stock expense activity, 2012

Beginning Balance:	$(11,086,811)
Issuance of Common Stock:	558,210
Tax Benefit - Options Exercised:	34,614
Excess Tax Benefits on Stock Comp:	1,230,724
Stock compensation accrual:	(5,714,302)
Ending Balance:	$(14,977,565)

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

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

Avista Corporation on June 28, 2012, redeemed the Stevens County Public Corporation Pollution Control Revenue Refunding Bonds (The Washington Water Power Company Kettle Falls Project), Series 1993, due in 12-01-2023 for the entire principal amount of $4.1 million at par.

On November 30, 2012, Avista Corporation issued $80.0 million of 4.23 percent First Mortgage Bonds due in 2047 under a bond purchase agreement with certain institutional investors in the private placement market. The new First Mortgage Bonds were issued under and in accordance with the Mortgage and Deed of Trust, dated as of June 1, 1939, from the Company to Citibank, N.A., trustee, as amended and supplemented by various supplemental indentures and other instruments. 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. 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;

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

Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

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

1. Report by Balance Sheet Account the details concerning long-term debt included in Account 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other Long-Term Debt.
2. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
3. For Advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
4. For receivers' certificates, show in column (a) the name of the court and date of court order under which such certificates were issued.

Line No.	Class and Series of Obligation and Name of Stock Exchange (a)	Nominal Date of Issue (b)	Date of Maturity (c)	Outstanding (Total amount outstanding without reduction for amts held by respondent) (d)
1	FMBS - SERIES A - 7.53% DUE 05/05/2023	05/06/1993	05/05/2023	5,500,000
2	FMBS - SERIES A - 7.37% DUE 05/10/2012	05/10/1993	05/10/2012	
3	FMBS - SERIES A - 7.54% DUE 5/05/2023	05/07/1993	05/05/2023	1,000,000
4	FMBS - SERIES A - 7.39% DUE 5/11/2018	05/11/1993	05/11/2018	7,000,000
5	FMBS - SERIES A - 7.45% DUE 6/11/2018	06/09/1993	06/11/2018	15,500,000
6	FMBS - SERIES A - 7.18% DUE 8/11/2023	08/12/1993	08/11/2023	7,000,000
7	KETTLE FALLS P C REV BONDS DUE 14	07/29/1993	12/01/2023	
8	ADVANCE ASSOCIATED-AVISTA CAPITAL II (ToPRS)	06/03/1997	06/01/2037	51,547,000
9	FMBS - 6.37% SERIES C	06/19/1998	06/19/2028	25,000,000
10	FMBS - 5.45% SERIES	11/18/2004	12/01/2019	90,000,000
11	FMBS - 6.25% SERIES	11/17/2005	12/01/2035	150,000,000
12	FMBS - 5.70% SERIES	12/15/2006	07/01/2037	150,000,000
13	FMBS - 5.95% SERIES	04/02/2008	06/01/2018	250,000,000
14	FMBS - 5.125% SERIES	09/22/2009	04/01/2022	250,000,000
15	COLSTRIP 2010A PCRBs DUE 2032	12/15/2010	10/01/2032	66,700,000
16	COLSTRIP 2010B PCRBs DUE 2034	12/15/2010	03/01/2034	17,000,000
17				
18	FMBS - 1.68% SERIES	12/30/2010	12/30/2013	50,000,000
19	FMBS - 3.89% SERIES	12/20/2010	12/20/2020	52,000,000
20	FMBS - 5.55% SERIES	12/20/2010	12/20/2040	35,000,000
21	FMBS - 4.45% SERIES	12/14/2011	12/14/2041	85,000,000
22				
23				
24				
25	FMBS - 4.23% SERIES	11/30/2012	11/29/2047	80,000,000
26				
27				
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40	TOTAL			1,388,247,000

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

5. In a supplemental statement, give explanatory details for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year (b) interest added to principal amount, and (c) principal repaid during year. Give Commission authorization numbers and dates.
6. If the respondent has pledged any of its long-term debt securities, give particulars (details) in a footnote, including name of the pledgee and purpose of the pledge.
7. If the respondent has any long-term securities that have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
8. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (f). Explain in a footnote any difference between the total of column (f) and the total Account 427, Interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
9. Give details concerning any long-term debt authorized by a regulatory commission but not yet issued.

Line No.	Interest for Year Rate (in %) (e)	Interest for Year Amount (f)	Held by Respondent Reacquired Bonds (Acct 222) (g)	Held by Respondent Sinking and Other Funds (h)	Redemption Price per $100 at End of Year (i)
1	7.530	414,150			
2	7.370	214,958			
3	7.540	75,400			
4	7.390	517,300			
5	7.450	1,154,750			
6	7.180	502,600			
7	6.000	120,950			
8	1.350	541,503			
9	6.370	1,592,500			
10	5.450	4,905,000			
11	6.250	9,375,000			
12	5.700	8,550,000			
13	5.950	14,875,000			
14	5.125	12,812,500			
15	0.463	309,043	66,700,000		
16	0.463	78,766	17,000,000		
17					
18	1.680	840,000			
19	3.890	2,022,800			
20	5.550	1,942,500			
21	4.450	3,782,500			
22					
23					
24					
25	4.230	291,400			
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39					
40		64,918,620	83,700,000		

FOOTNOTE DATA

Schedule Page: 256 Line No.: 8 Column: d

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

Schedule Page: 256 Line No.: 25 Column: a

The new issuance is based on the following 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.: 40 Column: f

The 427 and 430 account differences are primarily related to the amortization of settled interest rate swaps and other related interest expense items.

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Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

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

1. Report under separate subheadings for Unamortized Debt Expense, Unamortized Premium on Long-Term Debt and Unamortized Discount on Long-Term Debt, details of expense, premium or discount applicable to each class and series of long-term debt.
2. Show premium amounts by enclosing the figures in parentheses.
3. In column (b) show the principal amount of bonds or other long-term debt originally issued.
4. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.

Line No.	Designation of Long-Term Debt (a)	Principal Amount of Debt Issued (b)	Total Expense Premium or Discount (c)	Amortization Period Date From (d)	Amortization Period Date To (e)
1	FMBS - SERIES A - 7.53% DUE 05/05/2023	5,500,000	42,712	05/06/1993	05/05/2023
2	FMBS - SERIES A - 7.54% DUE 5/05/2023	1,000,000	7,766	05/07/1993	05/05/2023
3	FMBS - SERIES A - 7.37% DUE 5/10/2012	7,000,000	49,114	05/10/1993	05/10/2012
4	FMBS - SERIES A - 7.39% DUE 5/11/2018	7,000,000	54,364	05/11/1993	05/11/2018
5	FMBS - SERIES A - 7.45% DUE 6/11/2018	15,500,000	170,597	06/09/1993	06/11/2018
6	FMBS - SERIES A - 7.18% DUE 8/11/2023	7,000,000	54,364	08/12/1993	08/11/2023
7	KETTLE FALLS P C REV BONDS DUE 14	4,100,000	135,855	07/29/1993	12/01/2023
8	ADVANCE ASSOCIATED-AVISTA CAPITAL II (ToPRS)	51,547,000	1,296,086	06/03/1197	06/01/2037
9	SERIES C SET UP COST		666,169	06/15/1998	06/15/2013
10	FMBS - 6.37% SERIES C	25,000,000	158,304	06/19/1998	06/19/2028
11	FMBS - 5.45% SERIES	90,000,000	1,432,081	11/18/2004	12/01/2019
12	FMBS - 6.25% SERIES	150,000,000	2,180,435	11/17/2005	12/01/2035
13	FMBS - 5.70% SERIES	150,000,000	4,924,304	12/15/2006	07/01/2037
14	FMBS - 5.95% SERIES	250,000,000	3,081,419	04/02/2008	06/01/2018
15	FMBS - 5.125% SERIES	250,000,000	2,859,788	09/22/2009	04/01/2022
16	FMBS - 1.68% SERIES	50,000,000	305,790	12/30/2010	12/30/2013
17	FMBS - 3.89% SERIES	52,000,000	383,338	12/20/2010	12/20/2020
18	FMBS - 5.55% SERIES	35,000,000	258,834	12/20/2010	12/20/2040
19	Short-Term Credit Facility			12/14/2011	02/10/2017
20	4.45% SERIES DUE 12-14-2041	85,000,000	692,722	12/14/2011	12/14/2041
21	4.23% SERIES DUE 11-29-2047	80,000,000	725,635	11/30/2012	11/29/2047
22	Rathrum 2005		71,646	09/30/2005	12/01/2035
23	Debt Strategies		56,760	/ /	
24					
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Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

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

5. Furnish in a footnote 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.
6. Identify separately undisposed amounts applicable to issues which were redeemed in prior years.
7. Explain any debits and credits other than amortization debited to Account 428, Amortization of Debt Discount and Expense, or credited to Account 429, Amortization of Premium on Debt-Credit.

Line No.	Balance at Beginning of Year (f)	Debits During Year (g)	Credits During Year (h)	Balance at End of Year (i)
1	16,254		1,424	14,830
2	2,956		259	2,697
3	1,077		1,077	
4	13,953		2,175	11,778
5	44,355		6,824	37,531
6	21,142		1,812	19,330
7	55,163		55,163	
8	357,377		14,015	343,362
9	70,772		47,181	23,591
10	87,067		5,277	81,790
11	734,219		98,947	635,272
12	1,741,654		72,569	1,669,085
13	4,119,725		161,032	3,958,693
14	1,944,831		303,090	1,641,741
15	2,351,460		227,561	2,123,899
16	203,955		101,977	101,978
17	345,029		38,377	306,652
18	250,206		8,628	241,578
19	2,840,910		525,366	2,315,544
20	642,946	49,776	22,708	670,014
21		724,054		724,054
22	56,843		2,368	54,475
23	13,497		6,183	7,314
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Name of Respondent	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report 2012/Q4

FOOTNOTE DATA

Schedule Page: 258 Line No.: 23 Column: d

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Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

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

1. Report under separate subheadings for Unamortized Loss and Unamortized Gain on Reacquired Debt, details of gain and loss, including maturity date, on reacquisition applicable to each class and series of long-term debt. If gain or loss resulted from a refunding transaction, include also the maturity date of the new issue.
2. In column (c) show the principal amount of bonds or other long-term debt reacquired.
3. In column (d) show the net gain or net loss realized on each debt reacquisition as computed in accordance with General Instruction 17 of the Uniform Systems of Accounts.
4. Show loss amounts by enclosing the figures in parentheses.
5. Explain in a footnote any debits and credits other than amortization debited to Account 428.1, Amortization of Loss on Reacquired Debt, or credited to Account 429.1, Amortization of Gain on Reacquired Debt-Credit.

Line No.	Designation of Long-Term Debt (a)	Date Reacquired (b)	Principal of Debt Reacquired (c)	Net Gain or Loss (d)	Balance at Beginning of Year (e)	Balance at End of Year (f)
1	FMBS - 7.25% SERIES	12/20/2010	30,000,000		(5,646,298)	(5,018,931)
2	FMBS - 6.125% SERIES	12/20/2010	45,000,000		(5,088,361)	(4,912,900)
3	AVA Capital Trust III	04/01/2009	60,000,000		(2,369,170)	(2,139,896)
4	Misc Debt Repurchases I	05/10/1993			(1,331,831)	(1,132,224)
5	Misc Debt Repurchases II	06/19/1998			(103,757)	(97,469)
6	Misc Debt Repurchases III	07/29/1993			(57,755)	
7	Kettle Falls PCRBs	06/28/2012	4,100,000			104,770
8	Misc 2008 Repurchases Costs	01/01/2008			32,488	29,792
9	Misc 2006 Repurchases Costs	01/01/2006			(96,592)	(80,627)
10	Misc 2005 Repurchases Costs	01/01/2005			(983,868)	(885,227)
11	Misc 2004 Repurchases Costs	01/01/2004			(2,671,997)	(2,098,009)
12	Misc 2003 Repurchases Costs	01/01/2003			(393,133)	(315,799)
13	Misc 2002 Repurchases Costs	01/01/2002			(45,341)	(42,492)
14	Repurchase of 10 million of Capital II	12/01/2000	10,000,000		1,240,421	1,191,618
15	Misc 2002 Repurchase Gains	01/01/2002			874,467	819,527
16	Misc 2003 Repurchase Gains	01/01/2003			369,767	343,974
17	COLSTRIP 2010A PCRBs DUE 2032	12/10/2010	66,700,000		(3,237,046)	(3,087,411)
18	COLSTRIP 2010B PCRBs DUE 2034	12/10/2010	17,000,000		(1,044,481)	(1,749,450)
19						
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Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

Reconciliation of Reported Net Income with Taxable Income for Feder 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 that files consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be filed, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group members, tax assigned to each group member, and basis of allocation, assignments, or sharing of the consolidated tax among the group members.

Line No.	Details (a)	Amount (b)
1	Net Income for the Year (Page 116)	78,210,066
2	Reconciling Items for the Year	[redacted]
3		
4	Taxable Income Not Reported on Books	
5		3,398,971
6		
7		
8	TOTAL	3,398,971
9	Deductions Recorded on Books Not Deducted for Return	[redacted]
10		124,136,767
11		
12		
13	TOTAL	124,136,767
14	Income Recorded on Books Not Included in Return	[redacted]
15		14,239,687
16		
17		
18	TOTAL	14,239,687
19	Deductions on Return Not Charged Against Book Income	[redacted]
20		(205,058,564)
21		
22		
23		
24		
25		
26	TOTAL	(205,058,564)
27	Federal Tax Net Income	61,262,765
28	Show Computation of Tax:	
29	State Tax	379,911
30	Federal Rax Net Income less state tax	61,642,676
31		
32	Federal Tax @ 35%	21,574,937
33	Prior year & misc true ups	(8,077,924)
34	Cabinet Gorge Tax Credits	200,441
35	Total Federal Expense	13,311,067

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

1. Give details of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes). Enter the amounts in both columns (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 the portion of prepaid taxes charged 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 Beg. of Year Taxes Accrued (b)	Balance at Beg. of Year Prepaid Taxes (c)
1	FEDERAL:		
2	Income Tax 2009	(118,190)	
3	Income Tax 2010	142,150	
4	Income Tax 2011	(9,963,974)	
5	Income Tax (Current)		
6	Retained Earnings		
7	Prior Retained Earnings (2010)	(1,392,676)	
8	Prior Retained Earnings (2011)	(3,302,066)	
9	Current Retained Earnings		
10	Total Federal	(14,634,756)	
11			
12	STATE OF WASHINGTON		
13	Property Tax (2010)	(3,193)	
14	Property Tax (2011)	9,704,000	
15	Property Tax (2012)		
16	Excise Tax (2010)	(22,495)	
17	Excise Tax (2011)	2,585,031	
18	Excise Tax (2012)		
19	Natural Gas Use Tax	12,729	
20	Municipal Occupation Tax	3,123,004	
21	Sales & Use Tax (2006)	(8,173)	
22	Sales & Use Tax (2011)	186,525	
23	Sales & Use Tax (2012)		
24	Motor Vehicle Tax (2012)		
25	Total Washington	15,577,428	
26			
27	STATE OF IDAHO:		
28	Income Tax (2010)	(4,633)	
29	Income Tax (2011)	258,945	
30	Income Tax (2012)		
31	Property Tax (2009)	1,647	
32	Property Tax (2010)	(3,870)	
33	Property Tax (2011)	2,631,938	
34	Property Tax (2012)		
35	Motor Vehicle Tax (2012)		
36	Sales & Use Tax (2005)	436	
37	Sales & Use Tax (2010)		
38	Sales & Use Tax (2011)	42,032	
39	Sales & Use Tax (2012)		

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

5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a footnote. 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. Show in columns (i) thru (p) how the taxes accounts were distributed. Show both the utility department and number of account charged. For taxes charged to utility plant, show the number of the appropriate balance sheet plant account or subaccount.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.
10. Items under $250,000 may be grouped.
11. Report in column (q) the applicable effective state income tax rate.

Line No.	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)	Balance at End of Year Taxes Accrued (Account 236) (g)	Balance at End of Year Prepaid Taxes (Included in Acct 165) (h)
1					
2		(118,190)			
3	6,913,541	1,370,785	(6,552,932)	(868,026)	
4	(2,571,551)	(11,352,573)	5,321,340	4,138,388	
5	16,441,880	15,012,803		1,429,077	
6					
7				(1,392,676)	
8			1,231,592	(2,070,474)	
9	(1,994,624)			(1,994,624)	
10	18,789,246	4,912,825		(758,335)	
11					
12					
13	(8)	660	3,861		
14	171,510	9,871,649	(3,861)		
15	10,622,012			10,622,012	
16				(22,495)	
17	(17,932)	2,567,100			
18	24,039,256	21,712,032		2,327,224	
19	10,947	14,885	(8,181)	610	
20	22,227,744	22,808,413		2,542,334	
21				(8,173)	
22		186,514		12	
23	566,682	511,779		54,903	
24	5,473	5,473			
25	57,625,684	57,678,505	(8,181)	15,516,427	
26					
27					
28				(4,633)	
29	(129,632)	(6,327)		135,640	
30	377,042	400,000		(22,958)	
31	(1,640)	7			
32	3,870				
33	(36,462)	2,595,476			
34	6,179,245	2,902,249		3,276,997	
35	570	570			
36				436	
37					
38		42,032			
39	134,186	132,017		2,169	

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

1. Give details of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual or estimated amounts of such taxes are known, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes). Enter the amounts in both columns (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 the portion of prepaid taxes charged 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.

DISTRIBUTION OF TAXES CHARGED (Show utility department where applicable and account charged.)

Line No.	Electric (Account 408.1, 409.1) (i)	Gas (Account 408.1, 409.1) (j)	Other Utility Dept. (Account 408.1, 409.1) (k)	Other Income and Deductions (Account 408.2, 409.2) (l)
1				
2				
3	(73,728)		13,672	
4	(1,292,964)		(1,313,201)	
5	19,284,594	(1,964,559)	(1,342,747)	
6				
7				
8				
9				
10	17,917,902	(1,964,559)	(2,642,276)	
11				
12				
13		(8)		
14	145,116	5,098	21,642	
15	8,493,012	2,093,000	36,000	
16				
17	(20,384)	(1,867)	3,316	
18	18,386,314	5,567,862	85,550	
19	3,578			
20	16,405,423	5,413,949		
21				
22				
23				
24				
25	43,413,059	13,078,034	146,508	
26				
27				
28				
29	(103,706)	(25,926)		
30	388,842	(11,800)		
31	(1,640)			
32	4,316		(48)	
33	(76,485)	78,341	(11,877)	
34	5,064,040	1,112,585	10,630	
35				
36				
37				
38				
39				

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

5. If any tax (exclude Federal and State income taxes) covers more than one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a footnote. 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. Show in columns (i) thru (p) how the taxes accounts were distributed. Show both the utility department and number of account charged. For taxes charged to utility plant, show the number of the appropriate balance sheet plant account or subaccount.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.
10. Items under $250,000 may be grouped.
11. Report in column (q) the applicable effective state income tax rate.

DISTRIBUTION OF TAXES CHARGED (Show utility department where applicable and account charged.)

Line No.	Extraordinary Items (Account 409.3) (m)	Other Utility Opn. Income (Account 408.1, 409.1) (n)	Adjustment to Ret. Earnings (Account 439) (o)	Other (p)	State/Local Income Tax Rate (q)
1					
2					
3				6,973,597	
4				34,614	
5				464,593	
6					
7					
8					
9				(1,994,624)	
10				5,478,180	
11					
12					
13					
14				(346)	
15					
16					
17				1,003	
18				(470)	
19				7,369	
20				408,372	
21					
22					
23				566,682	
24				5,473	
25				988,083	
26					
27					
28					
29					
30					
31					
32				(398)	
33				(26,441)	
34				(8,010)	
35				570	
36					
37					
38					
39				134,186	

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

Line No.	Kind of Tax (See Instruction 5) (a)	Balance at Beg. of Year Taxes Accrued (b)	Balance at Beg. of Year Prepaid Taxes (c)
1	Irrigation Credits (2012)		
2	KWH Tax (2010)	1	
3	KWH Tax (2011)	20,705	
4	KWH Tax (2012)		
5	Franchise Tax (2010)	(15,507)	
6	Franchise Tax (2011)	1,629,882	
7	Franchise Tax (2012)		
8	Total Idaho	4,561,576	
9			
10	STATE OF MONTANA		
11	Income Tax (2010)	(171,969)	
12	Income Tax (2011)	489,040	
13	Income Tax (2012)		
14	Property Tax (2011)	3,454,233	
15	Property Tax (2012)		
16	Colstrip Generation Tax		
17	KWH Tax (2011)	267,607	
18	KWH Tax (2012)		
19	Motor Vehicle Tax (2012)		
20	Consumer Council Tax	6	
21	Public Commission Tax	10	
22	Total Montana	4,038,927	
23			
24	STATE OF OREGON		
25	Income Tax (2007)	(230,262)	
26	Income Tax (2010)	91,318	
27	Income Tax (2011)	386,749	
28	Income Tax (2012)		
29	Property Tax (2009)		
30	Property Tax (2010)	(1,791,031)	
31	Property Tax (2011)	(95,501)	
32	Property Tax (2012)		
33	Motor Vehicle Tax (2012)		
34	BETC Credit (2010)	1,448	
35	BETC Credit (2011)	(365,909)	
36	BETC Credit (2012)		
37	Glendate Regulatory Cr. 2008	(210,889)	
38	Glendate Regulatory Cr. 2009	70,289	
39	Franchise Tax (2010)	25,602	

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

Line No.	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)	Balance at End of Year Taxes Accrued (Account 236) (g)	Balance at End of Year Prepaid Taxes (Included in Acct 165) (h)
1					
2	1	2			
3	264	20,969			
4	399,680	364,000		35,680	
5			15,507		
6		1,614,375	(15,507)		
7	4,318,446	2,837,684		1,480,762	
8	11,245,570	10,903,054		4,904,093	
9					
10					
11		(179,683)		7,714	
12	(99,269)			389,771	
13	252,779	225,000		27,779	
14	965	3,455,198			
15	7,219,743	3,619,369		3,600,374	
16	3,048	3,048			
17		267,608			
18	1,137,780	858,252		279,528	
19	1,819	1,819			
20	50	21		34	
21	138	35		113	
22	8,517,053	8,250,667		4,305,313	
23					
24					
25			230,262		
26			(230,262)	(138,944)	
27	(379,351)			7,398	
28	356,742	125,000		231,742	
29					
30	1,894,942		(103,911)		
31	1,973,371	1,927,159	49,289		
32		2,030,655	54,622	(1,976,033)	
33	2,057	2,057			
34				1,448	
35				(365,909)	
36	(18,696)			(18,696)	
37				(210,889)	
38				70,289	
39		24,921		681	

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

DISTRIBUTION OF TAXES CHARGED (Show utility department where applicable and account charged.)

Line No.	Electric (Account 408.1, 409.1) (i)	Gas (Account 408.1, 409.1) (j)	Other Utility Dept. (Account 408.1, 409.1) (k)	Other Income and Deductions (Account 408.2, 409.2) (l)
1				
2	1			
3	264			
4	399,680			
5				
6				
7	3,150,983	1,160,207		
8	8,826,295	2,313,407	(1,295)	
9				
10				
11				
12	(99,269)			
13	252,779			
14	965			
15	7,219,743			
16	3,048			
17				
18	1,137,780			
19				
20	50			
21	138			
22	8,515,234			
23				
24				
25				
26				
27	(94,838)	(284,513)		
28	89,184	267,558		
29				
30	1,004,911	890,031		
31	896,176	1,077,196		
32				
33				
34				
35				
36				
37				
38				
39				

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

DISTRIBUTION OF TAXES CHARGED (Show utility department where applicable and account charged.)

Line No.	Extraordinary Items (Account 409.3) (m)	Other Utility Opn. Income (Account 408.1, 409.1) (n)	Adjustment to Ret. Earnings (Account 439) (o)	Other (p)	State/Local Income Tax Rate (q)
1					
2					
3					
4					
5					
6					
7				7,256	
8				107,163	
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19				1,819	
20					
21					
22				1,819	
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33				2,057	
34					
35					
36				(18,696)	
37					
38					
39					

Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

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

Line No.	Kind of Tax (See Instruction 5) (a)	Balance at Beg. of Year Taxes Accrued (b)	Balance at Beg. of Year Prepaid Taxes (c)
1	Franchise Tax (2011)	903,082	
2	Franchise Tax (2012)		
3	Total Oregon	(1,215,104)	
4			
5	STATE OF CALIFORNIA		
6	Income Tax (2010)	(800)	
7	Income Tax (2011)	(7,925)	
8	Income Tax (2012)		
9	Total California	(8,725)	
10			
11	MISCELLANEOUS STATES:		
12	Income Tax (2011)		
13	Income Tax (2012)		
14	Total Misc States		
15			
16	COUNTY & MUNICIPAL		
17	WA Renewable Energy	(561)	
18	Misc.	(26,441)	
19	Total County	(27,002)	
20			
21			
22			
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39			
	TOTAL	8,292,344	

Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

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

Line No.	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)	Balance at End of Year Taxes Accrued (Account 236) (g)	Balance at End of Year Prepaid Taxes (Included in Acct 165) (h)
1		876,166		26,916	
2	3,672,794	2,924,589		748,205	
3	7,501,859	7,910,547		(1,623,792)	
4					
5					
6		(800)			
7	1,600			(6,325)	
8		1,600		(1,600)	
9	1,600	800		(7,925)	
10					
11					
12					
13			(1)	(1)	
14			(1)	(1)	
15					
16					
17	(103,659)	(103,659)		(561)	
18	28,535	35,852	8,181	(25,577)	
19	(75,124)	(67,807)	8,181	(26,138)	
20					
21					
22					
23					
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29					
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37					
38					
39					
TOTAL	103,605,888	89,588,591	(1)	22,309,642	

Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

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

DISTRIBUTION OF TAXES CHARGED (Show utility department where applicable and account charged.)

Line No.	Electric (Account 408.1, 409.1) (i)	Gas (Account 408.1, 409.1) (j)	Other Utility Dept. (Account 408.1, 409.1) (k)	Other Income and Deductions (Account 408.2, 409.2) (l)
1				
2		3,650,378		
3	1,895,433	5,600,650		
4				
5				
6				
7		1,600		
8				
9		1,600		
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TOTAL	80,567,923	19,029,132	(2,497,063)	

Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

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

DISTRIBUTION OF TAXES CHARGED (Show utility department where applicable and account charged.)

Line No.	Extraordinary Items (Account 409.3) (m)	Other Utility Opn. Income (Account 408.1, 409.1) (n)	Adjustment to Ret. Earnings (Account 439) (o)	Other (p)	State/Local Income Tax Rate (q)
1					
2				22,416	
3				5,777	
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17				(103,659)	
18				28,535	
19				(75,124)	
20					
21					
22					
23					
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39					
TOTAL				6,505,898	

Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

Miscellaneous Current and Accrued Liabilities (Account 242)

1. Describe and report the amount of other current and accrued liabilities at the end of year.
2. Minor items (less than $250,000) may be grouped under appropriate title.

Line No.	Item (a)	Balance at End of Year (b)
1	Margin Call Deposit (242050)	470,000
2	Forest Use Permits (242060)	3,761,270
3	Settlement Payable (242090)	500,000
4	Mirabeau Accrued Rent (242095)	55,958
5	Audit Exp Acc (242200)	
6	FERC Admin Fee ACC (242300)	543,000
7	FERC Elec Admin Charge (242310)	88,522
8	MT Lease Payments (242375)	4,479,200
9	Misc Non Mon Power Exchange (242500)	70,279
10	DSM Tariff Rider	
11	Payroll EOLZTN (242700)	17,013,973
12	Low Income Energy Assist (242700)	3,618,273
13	Avista Grants Eng Sustain WSU-ASL (242780)	225,566
14	Mobius (242790)	250,000
15	Worker's Comp Liability (242830)	2,278,678
16	Accts Payable Inventory Accruals-SC (242900)	507,173
17	Accts Paybel Expense Accruals-SC (242910)	3,178,046
18	Current Portion-Benefit Liab	4,815,885
19	Misc Clearing Adjustments	19,475,834
20		
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45	Total	61,331,657

Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

Other Deferred Credits (Account 253)

1. Report below the details called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (less than $250,000) may be grouped by classes.

Line No.	Description of Other Deferred Credits (a)	Balance at Beginning of Year (b)	Debit Contra Account (c)	Debit Amount (d)	Credits (e)	Balance at End of Year (f)
1	Defer Gas Exchange (253028)	1,500,000	495	10		1,499,990
2	Pacificorp Capacitor (253080)					
3	Centralia Enviromental (253110)					
4	Rathdrum Refund (253120)	273,398	550	33,822		239,576
5	NE Tank Spill (253130)	70,367	186	53,570		16,797
6	Bills Pole Rentals (253140)	257,105			23,855	280,960
7	CR-CS2 GE LTSA (253150)				2,999,302	2,999,302
8						
9	Regulatory Accruals (253650)					
10	Sale/Leaseback on Bldg(253850)					
11	ID Clark Fork Relic	(452,847)			452,847	
12	Defer Comp Retired Execs (253900)	79,658	431	20,409		59,249
13	Defer Comp Active Execs (253910)	8,652,744			153,406	8,806,150
14	Executive Incent Plan (253920)	140,000				140,000
15	Unbilled Revenue (253990)	1,812,993	908	1,129,552		683,441
16						
17	DOC EECE Grant	850,255	136	97,705		752,550
18	DOC EECE Admin Fee					
19	Idaho Clark Fork	452,846		452,846		
20	ERM	12,947,628		12,947,628	8,756,638	8,756,638
21	Misc Def Debits				357,782	357,782
22	Credit Resource Mng				1,577,531	1,577,531
23						
24						
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44						
45	**Total**	**26,584,147**		**14,735,542**	**14,321,361**	**26,169,966**

Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

Accumulated Deferred Income Taxes-Other Property (Account 282)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	269,492,281	7,435,394	
3	Gas	96,448,805	5,665,663	
4	Other (Define) (footnote details)	32,559,207	7,690,353	
5	Total (Enter Total of lines 2 thru 4)	398,500,293	20,791,410	
6	Other (Specify) (footnote details)			
7	TOTAL Account 282 (Enter Total of lines 5 thr	398,500,293	20,791,410	
8	Classification of TOTAL			
9	Federal Income Tax	387,433,970	20,791,410	
10	State Income Tax	11,066,323		
11	Local Income Tax			

Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

Accumulated Deferred Income Taxes-Other Property (Account 282) (continued)

3. Provide in a footnote a summary of the type and amount of deferred income taxes reported in the beginning-of-year and end-of-year balances for deferred income taxes that the respondent estimates could be included in the development of jurisdictional recourse rates.

Line No.	Changes during Year Amounts Debited to Account 410.2 (e)	Changes during Year Amounts Credited to Account 411.2 (f)	Adjustments Debits Acct. No. (g)	Adjustments Debits Amount (h)	Adjustments Credits Account No. (i)	Adjustments Credits Amount (j)	Balance at End of Year (k)
1							
2							276,927,675
3							102,114,468
4	(75,090)						40,174,470
5	(75,090)						419,216,613
6							
7	(75,090)						419,216,613
8							
9	(75,090)						408,150,290
10							11,066,323
11							

Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

Accumulated Deferred Income Taxes-Other (Account 283)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Changes During Year Amounts Debited to Account 410.1 (c)	Changes During Year Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric	28,652,909	(8,327,674)	512,038
3	Gas	(3,884,914)	1,801,980	
4	Other (Define) (footnote details)	234,876,525	4,169,890	
5	Total (Total of lines 2 thru 4)	259,644,520	(2,355,804)	512,038
6	Other (Specify) (footnote details)			
7	TOTAL Account 283 (Total of lines 5 thru	259,644,520	(2,355,804)	512,038
8	Classification of TOTAL			
9	Federal Income Tax	255,410,714	(2,355,804)	512,038
10	State Income Tax	4,233,806		
11	Local Income Tax			

Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

Accumulated Deferred Income Taxes-Other (Account 283) (continued)

3. Provide in a footnote a summary of the type and amount of deferred income taxes reported in the beginning-of-year and end-of-year balances for deferred income taxes that the respondent estimates could be included in the development of jurisdictional recourse rates.

Line No.	Changes during Year Amounts Debited to Account 410.2 (e)	Changes during Year Amounts Credited to Account 411.2 (f)	Adjustments Debits Acct. No. (g)	Adjustments Debits Amount (h)	Adjustments Credits Account No. (i)	Adjustments Credits Amount (j)	Balance at End of Year (k)
1							
2	(1,537,191)					737,482	17,538,524
3						(279,708)	(1,803,226)
4		4,818,267		(4,281,489)			229,946,659
5	(1,537,191)	4,818,267		(4,281,489)		457,774	245,681,957
6							
7	(1,537,191)	4,818,267		(4,281,489)		457,774	245,681,957
8							
9	(1,537,191)	4,818,267		(4,281,489)		457,774	241,448,151
10							4,233,806
11							

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Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

Other Regulatory Liabilities (Account 254)

1. Report below the details called for concerning other regulatory liabilities which are created through the ratemaking actions of regulatory agencies (and not includable in other amounts).
2. For regulatory liabilities being amortized, show period of amortization in column (a).
3. Minor items (5% of the Balance at End of Year for Account 254 or amounts less than $250,000, whichever is less) may be grouped by classes.
4. Provide in a footnote, for each line item, the regulatory citation where the respondent was directed to refund the regulatory liability (e.g. Commission Order, state commission order, court decision).

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Beginning of Current Quarter/Year (b)	Written off during Quarter/Period Account Credited (c)	Written off During Period Amount Refunded (d)	Written off During Period Amount Deemed Non-Refundable (e)	Credits (f)	Balance at End of Current Quarter/Year (g)
1	Idaho Investment Tax Credit (254005)	12,316,743	190	8,670			12,308,073
2	Oregon BETC Credit (254010)	69,822				1,484,162	1,553,984
3	Noxon, ITC (254025)	2,737,108				606,909	3,344,017
4	Defer Gas Exchange (254028)						
5	FAS 109 Invest Tax Credit (254180)	126,252	190	22,644			103,608
6	Nez Perce (254220)	704,372	557	22,008			682,364
7	Oregon Senate Bill (254250)	771,592	407	842,062			(70,470)
8	Reg Liability CCX CR ID (254300)						
9	Accrue Lake CDA IPA int (254325)						
10	BPA Res Exch Regulatory Liab (254345)	178,328	186	178,328			
11	Unrealized Currency Exchange (254399)	11,097	143	7,495			3,602
12	Reg Liability Other (254700)						
13	Mark to Market ST (254740)	25,468	176	25,467			1
14	Mark to Market FAS133 (254750)						
15	Idaho DSIT	3,483,474	407	3,483,474			
16	Colstrip/CS2	516,251		516,250			1
17	Oregon Commercial Fee	(655)	805	1,288			(1,943)
18	Decoupling Rebate					5,531	5,531
19	Reg Liability WA Recs					93,222	93,222
20	Idaho PCA					18,566,192	18,566,192
21	SWAPS on FMBS					18,656,780	18,656,780
22							
23							
24							
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44							
45	Total	20,939,852		5,107,686	0	39,412,796	55,244,962

Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

Gas Operating Revenues

1. Report below natural gas operating revenues for each prescribed account total. The amounts must be consistent with the detailed data on succeeding pages.
2. Revenues in columns (b) and (c) include transition costs from upstream pipelines.
3. Other Revenues in columns (f) and (g) include reservation charges received by the pipeline plus usage charges, less revenues reflected in columns (b) through (e). Include in columns (f) and (g) revenues for Accounts 480-495.

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

Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

Gas Operating Revenues

4. If increases or decreases from previous year are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. On Page 108, include information on major changes during the year, new service, and important rate increases or decreases.
6. Report the revenue from transportation services that are bundled with storage services as transportation service revenue.

Line No.	Other Revenues Amount for Current Year (f)	Other Revenues Amount for Previous Year (g)	Total Operating Revenues Amount for Current Year (h)	Total Operating Revenues Amount for Previous Year (i)	Dekatherm of Natural Gas Amount for Current Year (j)	Dekatherm of Natural Gas Amount for Previous Year (k)
1	196,718,688	219,557,360	196,718,688	219,557,360	18,915,226	20,720,154
2	104,861,465	118,663,581	104,861,465	118,663,581	12,451,835	13,550,183
3						
4	160,769,449	210,967,741	160,769,449	210,967,741	60,478,027	53,875,981
5	291,260	347,915	291,260	347,915	38,137	44,000
6						
7						
8	169,923	168,994	169,923	168,994		
9						
10						
11	7,031,672	6,708,968	7,031,672	6,708,968	15,470,439	15,251,503
12						
13						
14						
15						
16	3,713	2,939	3,713	2,939		
17						
18	6,465,265	6,894,207	6,465,265	6,894,206		
19	476,311,435	563,311,705	476,311,435	563,311,704		
20						
21	476,311,435	563,311,705	476,311,435	563,311,704		

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Other Gas Revenues (Account 495)

Report below transactions of $250,000 or more included in Account 495, Other Gas Revenues. Group all transactions below $250,000 in one amount and provide the number of items.

Line No.	Description of Transaction (a)	Amount (in dollars) (b)
1	Commissions on Sale or Distribution of Gas of Others	
2	Compensation for Minor or Incidental Services Provided for Others	
3	Profit or Loss on Sale of Material and Supplies not Ordinarily Purchased for Resale	
4	Sales of Stream, Water, or Electricity, including Sales or Transfers to Other Departments	
5	Miscellaneous Royalties	
6	Revenues from Dehydration and Other Processing of Gas of Others except as provided for in the Instructions to Account 495	
7	Revenues for Right and/or Benefits Received from Others which are Realized Through Research, Development, and Demonstration Ventures	
8	Gains on Settlements of Imbalance Receivables and Payables	
9	Revenues from Penalties earned Pursuant to Tariff Provisions, including Penalties Associated with Cash-out Settlements	
10	Revenues from Shipper Supplied Gas	
11	Other revenues (Specify):	
12	Misc Bills	428,851
13	DSM Lost Margin (Oregon)	36,414
14	Deferred Exchange Revenue	6,000,000
15		
16		
17		
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	Total	**6,465,265**

Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

Gas Operation and Maintenance Expenses

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

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Gas Operation and Maintenance Expenses(continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
31	B2. Products Extraction		
32	Operation		
33	770 Operation Supervision and Engineering	0	0
34	771 Operation Labor	0	0
35	772 Gas Shrinkage	0	0
36	773 Fuel	0	0
37	774 Power	0	0
38	775 Materials	0	0
39	776 Operation Supplies and Expenses	0	0
40	777 Gas Processed by Others	0	0
41	778 Royalties on Products Extracted	0	0
42	779 Marketing Expenses	0	0
43	780 Products Purchased for Resale	0	0
44	781 Variation in Products Inventory	0	0
45	(Less) 782 Extracted Products Used by the Utility-Credit	0	0
46	783 Rents	0	0
47	TOTAL Operation (Total of lines 33 thru 46)	0	0
48	Maintenance		
49	784 Maintenance Supervision and Engineering	0	0
50	785 Maintenance of Structures and Improvements	0	0
51	786 Maintenance of Extraction and Refining Equipment	0	0
52	787 Maintenance of Pipe Lines	0	0
53	788 Maintenance of Extracted Products Storage Equipment	0	0
54	789 Maintenance of Compressor Equipment	0	0
55	790 Maintenance of Gas Measuring and Regulating Equipment	0	0
56	791 Maintenance of Other Equipment	0	0
57	TOTAL Maintenance (Total of lines 49 thru 56)	0	0
58	TOTAL Products Extraction (Total of lines 47 and 57)	0	0

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Gas Operation and Maintenance Expenses(continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
59	C. Exploration and Development		
60	Operation		
61	795 Delay Rentals	0	0
62	796 Nonproductive Well Drilling	0	0
63	797 Abandoned Leases	0	0
64	798 Other Exploration	0	0
65	TOTAL Exploration and Development (Total of lines 61 thru 64)	0	0
66	D. Other Gas Supply Expenses		
67	Operation		
68	800 Natural Gas Well Head Purchases	0	0
69	800.1 Natural Gas Well Head Purchases, Intracompany Transfers	0	0
70	801 Natural Gas Field Line Purchases	0	0
71	802 Natural Gas Gasoline Plant Outlet Purchases	0	0
72	803 Natural Gas Transmission Line Purchases	0	0
73	804 Natural Gas City Gate Purchases	324,767,750	419,658,497
74	804.1 Liquefied Natural Gas Purchases	0	0
75	805 Other Gas Purchases	0	0
76	(Less) 805.1 Purchases Gas Cost Adjustments	5,804,491	10,040,828
77	TOTAL Purchased Gas (Total of lines 68 thru 76)	318,963,259	409,617,669
78	806 Exchange Gas	0	0
79	Purchased Gas Expenses		
80	807.1 Well Expense-Purchased Gas	0	0
81	807.2 Operation of Purchased Gas Measuring Stations	0	0
82	807.3 Maintenance of Purchased Gas Measuring Stations	0	0
83	807.4 Purchased Gas Calculations Expenses	0	0
84	807.5 Other Purchased Gas Expenses	0	0
85	TOTAL Purchased Gas Expenses (Total of lines 80 thru 84)	0	0

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Gas Operation and Maintenance Expenses(continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
86	808.1 Gas Withdrawn from Storage-Debit	29,510,790	35,608,018
87	(Less) 808.2 Gas Delivered to Storage-Credit	23,177,606	41,974,554
88	809.1 Withdrawals of Liquefied Natural Gas for Processing-Debit	0	0
89	(Less) 809.2 Deliveries of Natural Gas for Processing-Credit	0	0
90	Gas used in Utility Operation-Credit		
91	810 Gas Used for Compressor Station Fuel-Credit	0	0
92	811 Gas Used for Products Extraction-Credit	1,648,718	1,866,763
93	812 Gas Used for Other Utility Operations-Credit	0	0
94	TOTAL Gas Used in Utility Operations-Credit (Total of lines 91 thru 93)	1,648,718	1,866,763
95	813 Other Gas Supply Expenses	1,881,894	2,060,484
96	TOTAL Other Gas Supply Exp. (Total of lines 77,78,85,86 thru 89,94,95)	325,529,619	403,444,854
97	TOTAL Production Expenses (Total of lines 3, 30, 58, 65, and 96)	325,529,619	403,444,854
98	2. NATURAL GAS STORAGE, TERMINALING AND PROCESSING EXPENSES		
99	A. Underground Storage Expenses		
100	Operation		
101	814 Operation Supervision and Engineering	18,245	13,813
102	815 Maps and Records	0	0
103	816 Wells Expenses	0	0
104	817 Lines Expense	0	0
105	818 Compressor Station Expenses	0	0
106	819 Compressor Station Fuel and Power	0	0
107	820 Measuring and Regulating Station Expenses	0	0
108	821 Purification Expenses	0	0
109	822 Exploration and Development	0	0
110	823 Gas Losses	0	0
111	824 Other Expenses	600,910	472,924
112	825 Storage Well Royalties	0	0
113	826 Rents	0	0
114	TOTAL Operation (Total of lines of 101 thru 113)	619,155	486,737

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Gas Operation and Maintenance Expenses(continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
115	Maintenance		
116	830 Maintenance Supervision and Engineering	0	0
117	831 Maintenance of Structures and Improvements	0	0
118	832 Maintenance of Reservoirs and Wells	0	0
119	833 Maintenance of Lines	0	0
120	834 Maintenance of Compressor Station Equipment	0	0
121	835 Maintenance of Measuring and Regulating Station Equipment	0	0
122	836 Maintenance of Purification Equipment	0	0
123	837 Maintenance of Other Equipment	504,736	430,728
124	TOTAL Maintenance (Total of lines 116 thru 123)	504,736	430,728
125	TOTAL Underground Storage Expenses (Total of lines 114 and 124)	1,123,891	917,465
126	B. Other Storage Expenses		
127	Operation		
128	840 Operation Supervision and Engineering	0	0
129	841 Operation Labor and Expenses	0	0
130	842 Rents	0	0
131	842.1 Fuel	0	0
132	842.2 Power	0	0
133	842.3 Gas Losses	0	0
134	TOTAL Operation (Total of lines 128 thru 133)	0	0
135	Maintenance		
136	843.1 Maintenance Supervision and Engineering	0	0
137	843.2 Maintenance of Structures	0	0
138	843.3 Maintenance of Gas Holders	0	0
139	843.4 Maintenance of Purification Equipment	0	0
140	843.5 Maintenance of Liquefaction Equipment	0	0
141	843.6 Maintenance of Vaporizing Equipment	0	0
142	843.7 Maintenance of Compressor Equipment	0	0
143	843.8 Maintenance of Measuring and Regulating Equipment	0	0
144	843.9 Maintenance of Other Equipment	0	0
145	TOTAL Maintenance (Total of lines 136 thru 144)	0	0
146	TOTAL Other Storage Expenses (Total of lines 134 and 145)	0	0

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Gas Operation and Maintenance Expenses(continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
147	C. Liquefied Natural Gas Terminaling and Processing Expenses		
148	Operation		
149	844.1 Operation Supervision and Engineering	0	0
150	844.2 LNG Processing Terminal Labor and Expenses	0	0
151	844.3 Liquefaction Processing Labor and Expenses	0	0
152	844.4 Liquefaction Transportation Labor and Expenses	0	0
153	844.5 Measuring and Regulating Labor and Expenses	0	0
154	844.6 Compressor Station Labor and Expenses	0	0
155	844.7 Communication System Expenses	0	0
156	844.8 System Control and Load Dispatching	0	0
157	845.1 Fuel	0	0
158	845.2 Power	0	0
159	845.3 Rents	0	0
160	845.4 Demurrage Charges	0	0
161	(less) 845.5 Wharfage Receipts-Credit	0	0
162	845.6 Processing Liquefied or Vaporized Gas by Others	0	0
163	846.1 Gas Losses	0	0
164	846.2 Other Expenses	0	0
165	TOTAL Operation (Total of lines 149 thru 164)	0	0
166	Maintenance		
167	847.1 Maintenance Supervision and Engineering	0	0
168	847.2 Maintenance of Structures and Improvements	0	0
169	847.3 Maintenance of LNG Processing Terminal Equipment	0	0
170	847.4 Maintenance of LNG Transportation Equipment	0	0
171	847.5 Maintenance of Measuring and Regulating Equipment	0	0
172	847.6 Maintenance of Compressor Station Equipment	0	0
173	847.7 Maintenance of Communication Equipment	0	0
174	847.8 Maintenance of Other Equipment	0	0
175	TOTAL Maintenance (Total of lines 167 thru 174)	0	0
176	TOTAL Liquefied Nat Gas Terminaling and Proc Exp (Total of lines 165 and 175)	0	0
177	TOTAL Natural Gas Storage (Total of lines 125, 146, and 176)	1,123,891	917,465

Gas Operation and Maintenance Expenses(continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
178	3. TRANSMISSION EXPENSES		
179	Operation		
180	850 Operation Supervision and Engineering	0	0
181	851 System Control and Load Dispatching	0	0
182	852 Communication System Expenses	0	0
183	853 Compressor Station Labor and Expenses	0	0
184	854 Gas for Compressor Station Fuel	0	0
185	855 Other Fuel and Power for Compressor Stations	0	0
186	856 Mains Expenses	0	0
187	857 Measuring and Regulating Station Expenses	0	0
188	858 Transmission and Compression of Gas by Others	0	0
189	859 Other Expenses	0	0
190	860 Rents	0	0
191	TOTAL Operation (Total of lines 180 thru 190)	0	0
192	Maintenance		
193	861 Maintenance Supervision and Engineering	0	0
194	862 Maintenance of Structures and Improvements	0	0
195	863 Maintenance of Mains	0	0
196	864 Maintenance of Compressor Station Equipment	0	0
197	865 Maintenance of Measuring and Regulating Station Equipment	0	0
198	866 Maintenance of Communication Equipment	0	0
199	867 Maintenance of Other Equipment	0	0
200	TOTAL Maintenance (Total of lines 193 thru 199)	0	0
201	TOTAL Transmission Expenses (Total of lines 191 and 200)	0	0
202	4. DISTRIBUTION EXPENSES		
203	Operation		
204	870 Operation Supervision and Engineering	1,741,877	1,527,573
205	871 Distribution Load Dispatching	0	0
206	872 Compressor Station Labor and Expenses	0	0
207	873 Compressor Station Fuel and Power	0	0

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Gas Operation and Maintenance Expenses(continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
208	874 Mains and Services Expenses	4,351,422	4,541,093
209	875 Measuring and Regulating Station Expenses-General	374,276	431,912
210	876 Measuring and Regulating Station Expenses-Industrial	9,972	34,524
211	877 Measuring and Regulating Station Expenses-City Gas Check Station	189,438	253,679
212	878 Meter and House Regulator Expenses	962,147	997,986
213	879 Customer Installations Expenses	2,438,556	2,574,363
214	880 Other Expenses	2,741,914	2,812,262
215	881 Rents	44,690	46,573
216	TOTAL Operation (Total of lines 204 thru 215)	12,854,292	13,219,965
217	Maintenance		
218	885 Maintenance Supervision and Engineering	151,586	222,923
219	886 Maintenance of Structures and Improvements	0	0
220	887 Maintenance of Mains	3,009,123	2,957,960
221	888 Maintenance of Compressor Station Equipment	0	0
222	889 Maintenance of Measuring and Regulating Station Equipment-General	330,619	212,883
223	890 Maintenance of Meas. and Reg. Station Equipment-Industrial	254,583	125,295
224	891 Maintenance of Meas. and Reg. Station Equip-City Gate Check Station	72,997	120,959
225	892 Maintenance of Services	1,679,077	1,257,549
226	893 Maintenance of Meters and House Regulators	1,728,218	1,449,627
227	894 Maintenance of Other Equipment	379,407	339,210
228	TOTAL Maintenance (Total of lines 218 thru 227)	7,605,610	6,686,406
229	TOTAL Distribution Expenses (Total of lines 216 and 228)	20,459,902	19,906,371
230	5. CUSTOMER ACCOUNTS EXPENSES		
231	Operation		
232	901 Supervision	514,213	562,996
233	902 Meter Reading Expenses	2,027,562	1,916,151
234	903 Customer Records and Collection Expenses	7,246,845	7,077,555

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Gas Operation and Maintenance Expenses(continued)

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
235	904 Uncollectible Accounts	1,894,921	2,339,734
236	905 Miscellaneous Customer Accounts Expenses	204,166	123,184
237	TOTAL Customer Accounts Expenses (Total of lines 232 thru 236)	11,887,707	12,019,620
238	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
239	Operation		
240	907 Supervision	0	0
241	908 Customer Assistance Expenses	9,662,065	15,489,692
242	909 Informational and Instructional Expenses	968,533	950,702
243	910 Miscellaneous Customer Service and Informational Expenses	156,805	118,938
244	TOTAL Customer Service and Information Expenses (Total of lines 240 thru 243)	10,787,403	16,559,332
245	7. SALES EXPENSES		
246	Operation		
247	911 Supervision	0	0
248	912 Demonstrating and Selling Expenses	9,538	9,884
249	913 Advertising Expenses	0	96
250	916 Miscellaneous Sales Expenses	0	(2,314)
251	TOTAL Sales Expenses (Total of lines 247 thru 250)	9,538	7,666
252	8. ADMINISTRATIVE AND GENERAL EXPENSES		
253	Operation		
254	920 Administrative and General Salaries	13,722,096	9,045,117
255	921 Office Supplies and Expenses	1,637,195	1,551,004
256	(Less) 922 Administrative Expenses Transferred-Credit	36,687	30,489
257	923 Outside Services Employed	4,454,643	5,461,172
258	924 Property Insurance	440,286	401,856
259	925 Injuries and Damages	1,163,461	1,347,333
260	926 Employee Pensions and Benefits	355,696	371,905
261	927 Franchise Requirements	0	0
262	928 Regulatory Commission Expenses	2,110,126	1,744,486
263	(Less) 929 Duplicate Charges-Credit	0	0
264	930.1General Advertising Expenses	796	288
265	930.2Miscellaneous General Expenses	1,368,295	1,148,499
266	931 Rents	362,461	316,193
267	TOTAL Operation (Total of lines 254 thru 266)	25,578,368	21,357,364
268	Maintenance		
269	932 Maintenance of General Plant	2,785,790	2,770,102
270	TOTAL Administrative and General Expenses (Total of lines 267 and 269)	28,364,158	24,127,466
271	TOTAL Gas O&M Expenses (Total of lines 97,177,201,229,237,244,251, and 270)	398,162,218	476,982,774

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Gas Used in Utility Operations

1. Report below details of credits during the year to Accounts 810, 811, and 812.
2. If any natural gas was used by the respondent for which a charge was not made to the appropriate operating expense or other account, list separately in column (c) the Dth of gas used, omitting entries in column (d).

Line No.	Purpose for Which Gas Was Used (a)	Account Charged (b)	Natural Gas Gas Used Dth (c)	Natural Gas Amount of Credit (in dollars) (d)	Natural Gas Amount of Credit (in dollars) (d)	Natural Gas Amount of Credit (in dollars) (d)
1	810 Gas Used for Compressor Station Fuel - Credit	804	4,085,538	0		
2	811 Gas Used for Products Extraction - Credit	811	2,145,630	1,648,718		
3	Gas Shrinkage and Other Usage in Respondent's Own Processing					
4	Gas Shrinkage, etc. for Respondent's Gas Processed by Others					
5	812 Gas Used for Other Utility Operations - Credit (Report separately for each principal use. Group minor uses.)					
6						
7						
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24						
25	**Total**		6,231,168	1,648,718		

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FOOTNOTE DATA

Schedule Page: 331 Line No.: 1 Column: d

Dollar values related to compressor fuel are not separately recorded. These dollars are included in total gas purchase costs.

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Other Gas Supply Expenses (Account 813)

1. Report other gas supply expenses by descriptive titles that clearly indicate the nature of such expenses. Show maintenance expenses, revaluation of monthly encroachments recorded in Account 117.4, and losses on settlements of imbalances and gas losses not associated with storage separately. Indicate the functional classification and purpose of property to which any expenses relate. List separately items of $250,000 or more.

Line No.	Description (a)	Amount (in dollars) (b)
1	Gas Resource Management	
2	Labor	663,194
3	Labor Loading	558,230
4	Other Expenses (Professional Services, Travel, Office Supplies, Training)	180,504
5		
6	Regulatory Affairs	
7	Labor	165,591
8	Labor Loading	139,207
9	Other Expenses (Travel, Transportation, Gas Technology Institute payments)	175,168
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11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25	**Total**	1,881,894

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Miscellaneous General Expenses (Account 930.2)

1. Provide the information requested below on miscellaneous general expenses.
2. For Other Expenses, show the (a) purpose, (b) recipient and (c) amount of such items. List separately amounts of $250,000 or more however, amounts less than $250,000 may be grouped if the number of items of so grouped is shown.

Line No.	Description (a)	Amount (in dollars) (b)
1	Industry association dues.	488,891
2	Experimental and general research expenses.	
	a. Gas Research Institute (GRI)	
	b. Other	
3	Publishing and distributing information and reports to stockholders, trustee, registrar, and transfer	
	agent fees and expenses, and other expenses of servicing outstanding securities of the respondent	41,480
4	Other expenses	
5	Director Fees and Expenses	234,358
6	Miscellaneous General Expenses	529,604
7	Community Relations	19,095
8	Educational - Informational	54,757
9	Other miscellaneous General Expenses	110
10		
11		
12		
13		
14		
15		
16		
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22		
23		
24		
25	**Total**	1,368,295

Schedule Page: 335 Line No.: 5 Column: b

Schedule Page: 335 Line No.: 10

Directors 2012	Expenses
Vendor Name	
HEIDI B STANLEY	$26,325
MARC F RACICOT	$23,691
ERIK J ANDERSON	$24,410
KRISTIANNE BLAKE	$24,453
REBECCA A KLEIN	$19,638
JOHN F KELLY	$30,846
MICHAEL L NOEL	$18,141
R JOHN TAYLOR	$20,925
SCOTT L MORRIS	$3,375
RICK R HOLLEY	$22,626
DONALD C BURKE	$19,929

Schedule Page: 335 Line No.: 6 Column: b

Schedule Page: 335 Line No.: 6

Vendor	Purpose	Amount
Vendors Under $5000		59,245
ALDERBROOK RESORT & SPA	Employee Lodging	1559.71
AMEREN	Professional Services	2734.94
AMERICAN GAS ASSOCIATION	Miscellaneous	20495
AMERICAN STOCK TRANSFER & TRUST CO	General Services	2251.3
AZAR'S FOOD SERVICES	Employee Business Meals	3090.52
BROADRIDGE ICS	General Services	22975.06
CITIBANK NA	Miscellaneous	17378.65
COATES KOKES	Professional Services	2050.26
COMPUTERSHARE SHAREOWNER SERVICES LLC	Postage	29266.4
CORP CREDIT CARD	Telecommunication Use	56255.72
CORPORATE RISK SOLUTIONS INC	Professional Services	0
CUTAWAY MEDIA	Miscellaneous	1956.92
DAVID D HOLMES	Office Supplies	834.76
DAVIS HIBBITTS & MIDGHALL INC	Professional Services	3843.95
DAVIS WRIGHT TREMAINE LLP	Miscellaneous	3686.16
DENNIS P VERMILLION	Employee Misc Expenses	1963.86
DESAUTEL HEGE COMMUNICATIONS	Professional Services	12136.84
DUFFY RESEARCH	Miscellaneous	2053.02
ENTERPRISE RENT A CAR	Miscellaneous	2450.16
HANNA & ASSOCIATES INC	Printing	4043.41
INLAND NORTHWEST PARTNERS	Subscriptions	1600.42
INNOVATE WASHINGTON FOUNDATION	Professional Services	9281.38
JASON R THACKSTON	Employee Misc	5097.76

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FOOTNOTE DATA

	Expenses	
KAREN S FELTES	Employee Misc Expenses	2881.85
KLUNDT HOSMER DESIGN	Professional Services	7291.55
MARK T THIES	Employee Misc Expenses	2472.82
MDI MARKETING	Advertising Expenses	2667.37
MELLON INVESTOR SERVICES LLC	Miscellaneous	6359.82
MICHAEL G ANDREA	Employee Misc Expenses	6960.12
MICHAEL J FAULKENBERRY	Employee Misc Expenses	7711.72
MOODYS INVESTORS SERVICE	Miscellaneous	37740.6
NYSE MARKET INC	General Services	15189.33
RICOH USA INC	Printing	2970.8
ROCKY MOUNTAIN INSTITUTE	Professional Services	6989
SIXTH MAN MARKETING LLC	Professional Services	3075.16
STANDARD & POORS	Miscellaneous	29625.78
THE BANK OF NEW YORK MELLON	Miscellaneous	3298.25
THE DAVENPORT HOTEL	Miscellaneous	5466.57
UNION BANK OF CALIFORNIA	Miscellaneous	9784.6
VAN NESS FELDMAN	Legal Services	6374.63

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

1. Report in Section A the amounts of depreciation expense, depletion and amortization for the accounts indicated and classified according to the plant functional groups shown.
2. Report in Section B, column (b) all depreciable or amortizable plant balances to which rates are applied and show a composite total. (If more desirable, report by plant account, subaccount or functional classifications other than those pre-printed in column (a). Indicate in a footnote the manner in which column (b) balances are

Section A. Summary of Depreciation, Depletion, and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Amortization Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization and Depletion of Producing Natural Gas Land and Land Rights (Account 404.1) (d)	Amortization of Underground Storage Land and Land Rights (Account 404.2) (e)
1	Intangible plant				228
2	Production plant, manufactured gas				
3	Production and gathering plant, natural gas				
4	Products extraction plant				
5	Underground gas storage plant	737,828			
6	Other storage plant				
7	Base load LNG terminaling and processing plant				
8	Transmission plant				
9	Distribution plant	14,449,547			
10	General plant	778,160			4,411
11	Common plant-gas	3,205,573			8,100
12	TOTAL	19,171,108			12,739

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

obtained. If average balances are used, state the method of averaging used. For column (c) report available information for each plant functional classification listed in column (a). If composite depreciation accounting is used, report available information called for in columns (b) and (c) on this basis. Where the unit-of-production method is used to determine depreciation charges, show in a footnote any revisions made to estimated gas reserves.

3. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state in a footnote the amounts and nature of the provisions and the plant items to which related.

Section A. Summary of Depreciation, Depletion, and Amortization Charges

Line No.	Amortization of Other Limited-term Gas Plant (Account 404.3) (f)	Amortization of Other Gas Plant (Account 405) (g)	Total (b to g) (h)	Functional Classification (a)
1	414,325		414,553	Intangible plant
2				Production plant, manufactured gas
3				Production and gathering plant, natural gas
4				Products extraction plant
5			737,828	Underground gas storage plant
6				Other storage plant
7				Base load LNG terminaling and processing plant
8				Transmission plant
9			14,449,547	Distribution plant
10			782,571	General plant
11	2,200,415		5,414,088	Common plant-gas
12	2,614,740		21,798,587	TOTAL

Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

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

4. Add rows as necessary to completely report all data. Number the additional rows in sequence as 2.01, 2.02, 3.01, 3.02, etc.

Section B. Factors Used in Estimating Depreciation Charges

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

Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

Particulars Concerning Certain Income Deductions and Interest Charges Accounts

Report the information specified below, in the order given, for the respective income deduction and interest charges accounts.

(a) Miscellaneous Amortization (Account 425)-Describe the nature of items included in this account, the contra account charged, the total of amortization charges for the year, and the period of amortization.

(b) Miscellaneous Income Deductions-Report the nature, payee, and amount of other income deductions for the year as required by Accounts 426.1, Donations; 426.2, Life Insurance; 426.3, Penalties; 426.4, Expenditures for Certain Civic, Political and Related Activities; and 426.5, Other Deductions, of the Uniform System of Accounts. Amounts of less than $250,000 may be grouped by classes within the above accounts.

(c) Interest on Debt to Associated Companies (Account 430)-For each associated company that incurred interest on debt during the year, indicate the amount and interest rate respectively for (a) advances on notes, (b) advances on open account, (c) notes payable, (d) accounts payable, and (e) other debt, and total interest. Explain the nature of other debt on which interest was incurred during the year.

(d) Other Interest Expense (Account 431) - Report details including the amount and interest rate for other interest charges incurred during the year.

Line No.	Item (a)	Amount (b)
1	Acct. 425.00 Miscellaneous Amortizations	
2	Items under $250,000	
3	Total - 425.00	
4	Acct. 426.10 Donations	
5	Items under $250,000	2,272,123
6	Total - 426.10	2,272,123
7	Acct. 426.20 Life Insurance	
8	Officers Life Insurance	162,955
9	SERP	2,306,433
10	Items under $250,000	64,164
11	Total - 426.20	2,533,552
12	Acct. 426.30	
13	Items under $250,000	15,251
14	Total - 426.30	15,251
15	Acct. 426.40 Exp. for Certain Civic, Political and Related Activities	
16	Items under $250,000	1,414,338
17	Total - 426.40	1,414,338
18	Acct. 426.50 Other Deductions	
19	Executive Deferred Compensation	856,263
20	Items under $250,000	959,063
21	Total - 426.50	1,815,326
22	Acct. 430.00 Interest on Debt to Assoc. Companies	
23	Avista Capital II (long-term debt) (variable rate ranged from 1.19 to 1.40 pct.)	541,503
24	Avista Capital, Inc.	343,620
25	Total - 430.00	885,123
26	Acct 431.00 Other Interest Expense	
27	Interest on electric deferrals	648,676
28	Interest on natural gas deferrals	664,048
29	Interest on committed line of credit	751,925
30	Interest on demand side management programs	211,752
31	Interest related to IRS audits	253,118
32	Other	52,888
33	Total 431.00	2,582,407
34		
35		

Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

Regulatory Commission Expenses (Account 928)

1. Report below details of regulatory commission expenses incurred during the current year (or in previous years, if being amortized) relating to formal cases before a regulatory body, or cases in which such a body was a party.
2. In column (b) and (c), indicate whether the expenses were assessed by a regulatory body or were otherwise incurred by the utility.

Line No.	Description (Furnish name of regulatory commission or body, the docket number, and a description of the case.) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expenses to Date (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Federal Energy Regulatory Commission				
2	Charges include annual fee and license fee				
3	for the Spokane River Project, the Cabinet				
4	Gorge Project and Noxon Rapids Project	2,431,364	185,496	2,616,860	
5					
6	Washington Utilities and Transportation Commission				
7	Includes annual fee and various other electric dockets	960,565	1,301,327	2,261,892	
8					
9	Includes annual fee and various other natural gas dockets	320,188	495,445	815,633	
10					
11	Idaho Public Utilities Commission				
12	Includes annual fee and various other electric dockets	620,838	245,606	866,444	
13					
14	Includes annual fee and various other natural gas dockets	172,199	111,074	283,273	
15					
16	Public Utility Commission of Oregon				
17	Includes annual fee and various other dockets	528,779	127,724	656,503	
18					
19	Not directly assigned electric		913,764	913,764	
20	Not directly assigned natural gas		354,716	354,716	
21					
22					
23					
24					
25	**Total**	5,033,933	3,735,152	8,769,085	

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Regulatory Commission Expenses (Account 928)

3. Show in column (k) any expenses incurred in prior years that are being amortized. List in column (a) the period of amortization.
4. Identify separately all annual charge adjustments (ACA).
5. List in column (f), (g), and (h) expenses incurred during year which were charges currently to income, plant, or other accounts.
6. Minor items (less than $250,000) may be grouped.

Line No.	Expenses Incurred During Year Charged Currently To Department (f)	Expenses Incurred During Year Charged Currently To Account No. (g)	Expenses Incurred During Year Charged Currently To Amount (h)	Expenses Incurred During Year Deferred to Account 182.3 (i)	Amortized During Year Contra Account (j)	Amortized During Year Amount (k)	Deferred in Account 182.3 End of Year (l)
1							
2							
3							
4	Electric	928	2,616,860				
5							
6							
7	Electric	928	2,261,892				
8							
9	Gas	928	815,633				
10							
11							
12	Electric	928	866,444				
13							
14	Gas	928	283,273				
15							
16							
17	Gas	928	656,503				
18							
19	Electric	928	913,764				
20	Gas	928	354,716				
21							
22							
23							
24							
25			8,769,085				

Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

Employee Pensions and Benefits (Account 926)

1. Report below the items contained in Account 926, Employee Pensions and Benefits.

Line No.	Expense (a)	Amount (b)
1	Pensions – defined benefit plans	300,135
2	Pensions – other	
3	Post-retirement benefits other than pensions (PBOP)	55,561
4	Post- employment benefit plans	
5	Other (Specify)	
6		
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	Total	**355,696**

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Distribution of Salaries and Wages

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals and Other Accounts, and enter such amounts in the appropriate lines and columns provided. Salaries and wages billed to the Respondent by an affiliated company must be assigned to the particular operating function(s) relating to the expenses.

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

Line No.	Classification (a)	Direct Payroll Distribution (b)	Payroll Billed by Affiliated Companies (c)	Allocation of Payroll Charged for Clearing Accounts (d)	Total (e)
1	Electric				
2	Operation				
3	Production	10,264,200			10,264,200
4	Transmission	2,656,676			2,656,676
5	Distribution	7,508,530			7,508,530
6	Customer Accounts	6,924,109			6,924,109
7	Customer Service and Informational	711,342			711,342
8	Sales	5,487			5,487
9	Administrative and General	16,143,773			16,143,773
10	TOTAL Operation (Total of lines 3 thru 9)	44,214,117			44,214,117
11	Maintenance				
12	Production	3,410,007			3,410,007
13	Transmission	985,166			985,166
14	Distribution	4,058,266			4,058,266
15	Administrative and General		10,330,471		10,330,471
16	TOTAL Maintenance (Total of lines 12 thru 15)	8,453,439	10,330,471		18,783,910
17	Total Operation and Maintenance				
18	Production (Total of lines 3 and 12)	13,674,207			13,674,207
19	Transmission (Total of lines 4 and 13)	3,641,842			3,641,842
20	Distribution (Total of lines 5 and 14)	11,566,796			11,566,796
21	Customer Accounts (line 6)	6,924,109			6,924,109
22	Customer Service and Informational (line 7)	711,342			711,342
23	Sales (line 8)	5,487			5,487
24	Administrative and General (Total of lines 9 and 15)	16,143,773	10,330,471		26,474,244
25	TOTAL Operation and Maintenance (Total of lines 18 thru 24)	52,667,556	10,330,471		62,998,027
26	Gas				
27	Operation				
28	Production - Manufactured Gas				
29	Production - Natural Gas(Including Exploration and Development)				
30	Other Gas Supply	828,785			828,785
31	Storage, LNG Terminaling and Processing	8,363			8,363
32	Transmission				
33	Distribution	3,578,184			3,578,184
34	Customer Accounts	2,710,084			2,710,084
35	Customer Service and Informational	349,486			349,486
36	Sales	1,488			1,488
37	Administrative and General	5,910,809			5,910,809
38	TOTAL Operation (Total of lines 28 thru 37)	13,387,199			13,387,199
39	Maintenance				
40	Production - Manufactured Gas				
41	Production - Natural Gas(Including Exploration and Development)				
42	Other Gas Supply				
43	Storage, LNG Terminaling and Processing				
44	Transmission	866,735			866,735
45	Distribution	2,641,810			2,641,810

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Distribution of Salaries and Wages (continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Payroll Billed by Affiliated Companies (c)	Allocation of Payroll Charged for Clearing Accounts (d)	Total (e)
46	Administrative and General		3,381,109		3,381,109
47	TOTAL Maintenance (Total of lines 40 thru 46)	3,508,545	3,381,109		6,889,654
48	Gas (Continued)				
49	Total Operation and Maintenance				
50	Production - Manufactured Gas (Total of lines 28 and 40)				
51	Production - Natural Gas (Including Expl. and Dev.)(ll. 29 and 41)				
52	Other Gas Supply (Total of lines 30 and 42)	828,785			828,785
53	Storage, LNG Terminaling and Processing (Total of ll. 31 and 43)	8,363			8,363
54	Transmission (Total of lines 32 and 44)	866,735			866,735
55	Distribution (Total of lines 33 and 45)	6,219,994			6,219,994
56	Customer Accounts (Total of line 34)	2,710,084			2,710,084
57	Customer Service and Informational (Total of line 35)	349,486			349,486
58	Sales (Total of line 36)	1,488			1,488
59	Administrative and General (Total of lines 37 and 46)	5,910,809	3,381,109		9,291,918
60	Total Operation and Maintenance (Total of lines 50 thru 59)	16,895,744	3,381,109		20,276,853
61	Other Utility Departments				
62	Operation and Maintenance				
63	TOTAL ALL Utility Dept. (Total of lines 25, 60, and 62)	69,563,300	13,711,580		83,274,880
64	Utility Plant				
65	Construction (By Utility Departments)				
66	Electric Plant	29,696,485	9,212,974		38,909,459
67	Gas Plant	8,275,727	2,948,876		11,224,603
68	Other				
69	TOTAL Construction (Total of lines 66 thru 68)	37,972,212	12,161,850		50,134,062
70	Plant Removal (By Utility Departments)				
71	Electric Plant	1,508,765	290,831		1,799,596
72	Gas Plant	124,325	23,965		148,290
73	Other				
74	TOTAL Plant Removal (Total of lines 71 thru 73)	1,633,090	314,796		1,947,886
75	Other Accounts (Specify) (footnote details)	31,023,866	(26,241,727)		4,782,139
76	TOTAL Other Accounts	31,023,866	(26,241,727)		4,782,139
77	TOTAL SALARIES AND WAGES	140,192,468	(53,501)		140,138,967

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FOOTNOTE DATA

Schedule Page: 354 Line No.: 75 Column: e

Stores Expense (163)	1,901,710	(1,901,710)	0
Unamortized debt expense (181)	0		0
Regulatory Assets (182)	0		0
Preliminary Survey and Investigation (183)	71,274		71,274
Small Tool Expense (184)	3,296,582	(3,296,582)	0
Miscellaneous Deferred Debits (186)	1,349,092		1,349,092
Capital Stock Expense (214)	0		0
Merchandising Expenses (416)	0		0
Non-operating Expenses (417)	747,089		747,089
Expenditures of Certain Civic, Political and Related			0
Activities (426)	620,960		620,960
Employee Incentive Plan (232380)	4,843,441	(4,843,441)	0
DSM Tarrif Rider and Payroll Equalization Liability (242600, 242700)	18,112,648	(16,199,994)	1,912,654
Incentive / Stock Compensation (238000)	81,070		81,070
			0
			0
TOTAL Other Accounts	31,023,866	(26,241,727)	4,782,139

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Name of Respondent	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2013	Year/Period of Report End of 2012/Q4

Charges for Outside Professional and Other Consultative Services

1. Report the information specified below for all charges made during the year included in any account (including plant accounts) for outside consultative and other professional services. These services include rate, management, construction, engineering, research, financial, valuation, legal, accounting, purchasing, advertising,labor relations, and public relations, rendered for the respondent under written or oral arrangement, for which aggregate payments were made during the year to any corporation partnership, organization of any kind, or individual (other than for services as an employee or for payments made for medical and related services) amounting to more than $250,000, including payments for legislative services, except those which should be reported in Account 426.4 Expenditures for Certain Civic, Political and Related Activities.
 (a) Name of person or organization rendering services.
 (b) Total charges for the year.
2. Sum under a description "Other", all of the aforementioned services amounting to $250,000 or less.
3. Total under a description "Total", the total of all of the aforementioned services.
4. Charges for outside professional and other consultative services provided by associated (affiliated) companies should be excluded from this schedule and be reported on Page 358, according to the instructions for that schedule.

Line No.	Description (a)	Amount (in dollars) (b)
1	AECOM TECHNICAL SERVICES INC	371,555
2	AQUA TECHNEX	446,359
3	BAIN & COMPANY INC	1,445,669
4	BAKER CONSTRUCTION & DEVELOPMENT INC	2,692,983
5	BOOZ & COMPANY INC	595,139
6	CATS EYE EXCAVATING INC	596,348
7	COBRA BEC INC	450,696
8	COEUR D ALENE TRIBE	427,238
9	COLUMBIA GRID	399,008
10	COMPUTER FINANCIAL CONSULTANTS INC	324,414
11	DAVIS WRIGHT TREMAINE LLP	281,532
12	DINERO SOLUTIONS LLC	506,437
13	EFACEC ADVANCED CONTROL SYSTEMS	325,934
14	ELECTRICAL CONSULTANTS INC	631,055
15	EP2M LLC	2,119,166
16	GARCO CONSTRUCTION INC	3,094,616
17	GARTNER INC	288,000
18	HANNA & ASSOCIATES INC	518,459
19	IBM CORPORATION	908,160
20	INTERIOR SOLUTIONS INC	470,304
21	JAMES A CAROTHERS	250,000
22	LAND EXPRESSIONS	376,691
23	MAGNER SANBORN	873,892
24	MANSFIELD GAS EQUIPMENT SYSTEMS	1,522,336
25	MAX J KUNEY COMPANY	324,919
26	MCKINSTRY ESSENTION INC	3,523,557
27	MWH AMERICAS INC	546,356
28	NORTHWEST HYDRAULIC CONSULTANTS	477,804
29	PAINE HAMBLEN LLP	730,400
30	POWER PLAN INC	621,460
31	PRICEWATERHOUSE COOPERS LLP	255,302
32	PRO BUILDING SYSTEMS	259,434
33	SAPERE CONSULTING INC	307,505
34	SPIRAE INC	438,828
35	TILTON EXCAVATON LLC	324,246

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Charges for Outside Professional and Other Consultative Services (continued)

Line No.	Description (a)	Amount (in dollars) (b)
1	URS CORPORATION	304,961
2	URS ENERGY & CONSTRUCTION INC	438,211
3	US FOREST SERVICE	319,005
4	WESTERN ELECTRICITY	561,133
5	WIN MILL SOFTWARE INC	333,266
6	CERIUM NETWORKS	308,016
7	DELOITTE & TOUCHE LLP	1,677,830
8	Other	21,697,438
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Transactions with Associated (Affiliated) Companies

1. Report below the information called for concerning all goods or services received from or provided to associated (affiliated) companies amounting to more than $250,000.
2. Sum under a description "Other", all of the aforementioned goods and services amounting to $250,000 or less.
3. Total under a description "Total", the total of all of the aforementioned goods and services.
4. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote the basis of the allocation.

Line No.	Description of the Good or Service (a)	Name of Associated/Affiliated Company (b)	Account(s) Charged or Credited (c)	Amount Charged or Credited (d)
1	Goods or Services Provided by Affiliated Company			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	Goods or Services Provided for Affiliated Company			
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22				
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Gas Storage Projects

1. Report injections and withdrawals of gas for all storage projects used by respondent.

Line No.	Item (a)	Gas Belonging to Respondent (Dth) (b)	Gas Belonging to Others (Dth) (c)	Total Amount (Dth) (d)
	STORAGE OPERATIONS (in Dth)			
1	Gas Delivered to Storage			
2	January	274,154		274,154
3	February	(11,595)		(11,595)
4	March	863,671		863,671
5	April	1,037,110		1,037,110
6	May	2,683,096		2,683,096
7	June	2,806,026		2,806,026
8	July	142,804		142,804
9	August	1,552,236		1,552,236
10	September	922,548		922,548
11	October	82,884		82,884
12	November	24,923		24,923
13	December	9,276		9,276
14	TOTAL (Total of lines 2 thru 13)	10,387,133		10,387,133
15	Gas Withdrawn from Storage			
16	January	2,722,606		2,722,606
17	February	2,592,318		2,592,318
18	March	158,823		158,823
19	April	39,000		39,000
20	May	159,054		159,054
21	June	72,000		72,000
22	July	17,684		17,684
23	August	1,536,560		1,536,560
24	September	932,467		932,467
25	October	50,000		50,000
26	November	89,040		89,040
27	December	788,069		788,069
28	TOTAL (Total of lines 16 thru 27)	9,157,621		9,157,621

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Gas Storage Projects

1. On line 4, enter the total storage capacity certificated by FERC.
2. Report total amount in Dth or other unit, as applicable on lines 2, 3, 4, 7. If quantity is converted from Mcf to Dth, provide conversion factor in a footnote.

Line No.	Item (a)	Total Amount (b)
	STORAGE OPERATIONS	
1	Top or Working Gas End of Year	8,528,000 Dth
2	Cushion Gas (Including Native Gas)	7,730,668 Dth
3	Total Gas in Reservoir (Total of line 1 and 2)	16,258,668 Dth
4	Certificated Storage Capacity	16,258,668 Dth
5	Number of Injection - Withdrawal Wells	54
6	Number of Observation Wells	48
7	Maximum Days' Withdrawal from Storage	133,267 Dth
8	Date of Maximum Days' Withdrawal	01/18/2012
9	LNG Terminal Companies (in Dth)	
10	Number of Tanks	
11	Capacity of Tanks	
12	LNG Volume	
13	Received at "Ship Rail"	
14	Transferred to Tanks	
15	Withdrawn from Tanks	
16	"Boil Off" Vaporization Loss	

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FOOTNOTE DATA

Schedule Page: 513 Line No.: 7 Column: c

Mcf converted to Dth using factor of 1.04

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Auxiliary Peaking Facilities

1. Report below auxiliary facilities of the respondent for meeting seasonal peak demands on the respondent's system, such as underground storage projects, liquefied petroleum gas installations, gas liquefaction plants, oil gas sets, etc.
2. For column (c), for underground storage projects, report the delivery capacity on February 1 of the heating season overlapping the year-end for which this report is submitted. For other facilities, report the rated maximum daily delivery capacities.
3. For column (d), include or exclude (as appropriate) the cost of any plant used jointly with another facility on the basis of predominant use, unless the auxiliary peaking facility is a separate plant as contemplated by general instruction 12 of the Uniform System of Accounts.

Line No.	Location of Facility (a)	Type of Facility (b)	Maximum Daily Delivery Capacity of Facility Dth (c)	Cost of Facility (in dollars) (d)	Was Facility Operated on Day of Highest Transmission Peak Delivery?
1					
2	Chehalis, Washington	Underground Natural Gas	358,800	34,678,708	
3		Storage Field			
4		Washington & Idaho Supply			
5					
6	Chehalis, Washington	Underground Natural Gas	39,867	5,751,589	
7		Storage Field			
8		Oregon Supply			
9					
10	Chehalis, Washington	Underground Natural Gas	2,623		
11		Storage Field			
12		Oregon Supply			
13					
14	Rock Springs, Wyoming	Underground Natural Gas	186,125		
15		Storage Field			
16		Washington & Idaho Supply			
17					
18	Rock Springs, Wyoming	Underground Natural Gas	63,875		
19		Storage Field			
20		Oregon Supply			
21					
22					
23					
24					
25					
26					
27					
28					
29					
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FOOTNOTE DATA

Schedule Page: 519 Line No.: 10 Column: d
Respondent is a participant in the facilities, not an owner and is charged a fee for demand deliverability and capacity.

Schedule Page: 519 Line No.: 14 Column: d
Respondent is a participant in the facilities, not an owner and is charged a fee for demand deliverability and capacity.

Schedule Page: 519 Line No.: 18 Column: d
Respondent is a participant in the facilities, not an owner and is charged a fee for demand deliverability and capacity.

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Gas Account - Natural Gas

1. The purpose of this schedule is to account for the quantity of natural gas received and delivered by the respondent.
2. Natural gas means either natural gas unmixed or any mixture of natural and manufactured gas.
3. Enter in column (c) the year to date Dth as reported in the schedules indicated for the items of receipts and deliveries.
4. Enter in column (d) the respective quarter's Dth as reported in the schedules indicated for the items of receipts and deliveries.
5. Indicate in a footnote the quantities of bundled sales and transportation gas and specify the line on which such quantities are listed.
6. If the respondent operates two or more systems which are not interconnected, submit separate pages for this purpose.
7. Indicate by footnote the quantities of gas not subject to Commission regulation which did not incur FERC regulatory costs by showing (1) the local distribution volumes another jurisdictional pipeline delivered to the local distribution company portion of the reporting pipeline (2) the quantities that the reporting pipeline transported or sold through its local distribution facilities or intrastate facilities and which the reporting pipeline received through gathering facilities or intrastate facilities, but not through any of the interstate portion of the reporting pipeline, and (3) the gathering line quantities that were not destined for interstate market or that were not transported through any interstate portion of the reporting pipeline.
8. Indicate in a footnote the specific gas purchase expense account(s) and related to which the aggregate volumes reported on line No. 3 relate.
9. Indicate in a footnote (1) the system supply quantities of gas that are stored by the reporting pipeline, during the reporting year and also reported as sales,transportation and compression volumes by the reporting pipeline during the same reporting year, (2) the system supply quantities of gas that are stored by the reporting pipeline during the reporting year which the reporting pipeline intends to sell or transport in a future reporting year, and (3) contract storage quantities.
10. Also indicate the volumes of pipeline production field sales that are included in both the company's total sales figure and the company's total transportation figure. Add additional information as necessary to the footnotes.

Line No.	Item (a)	Ref. Page No. of (FERC Form Nos. 2/2-A) (b)	Total Amount of Dth Year to Date (c)	Current Three Months Ended Amount of Dth Quarterly Only
01	Name of System:			
2	GAS RECEIVED			
3	Gas Purchases (Accounts 800-805)		94,679,606	
4	Gas of Others Received for Gathering (Account 489.1)	303		
5	Gas of Others Received for Transmission (Account 489.2)	305		
6	Gas of Others Received for Distribution (Account 489.3)	301	15,470,439	
7	Gas of Others Received for Contract Storage (Account 489.4)	307		
8	Gas of Others Received for Production/Extraction/Processing (Account 490 and 491)			
9	Exchanged Gas Received from Others (Account 806)	328		
10	Gas Received as Imbalances (Account 806)	328	83,769	
11	Receipts of Respondent's Gas Transported by Others (Account 858)	332		
12	Other Gas Withdrawn from Storage (Explain)			
13	Gas Received from Shippers as Compressor Station Fuel			
14	Gas Received from Shippers as Lost and Unaccounted for			
15	Other Receipts (Specify) (footnote details)			
16	Total Receipts (Total of lines 3 thru 15)		110,233,814	
17	GAS DELIVERED			
18	Gas Sales (Accounts 480-484)		91,883,224	
19	Deliveries of Gas Gathered for Others (Account 489.1)	303		
20	Deliveries of Gas Transported for Others (Account 489.2)	305		
21	Deliveries of Gas Distributed for Others (Account 489.3)	301	15,470,439	
22	Deliveries of Contract Storage Gas (Account 489.4)	307		
23	Gas of Others Delivered for Production/Extraction/Processing (Account 490 and 491)			
24	Exchange Gas Delivered to Others (Account 806)	328		
25	Gas Delivered as Imbalances (Account 806)	328		
26	Deliveries of Gas to Others for Transportation (Account 858)	332		
27	Other Gas Delivered to Storage (Explain)		(1,205,387)	
28	Gas Used for Compressor Station Fuel	509	4,085,538	
29	Other Deliveries and Gas Used for Other Operations			
30	Total Deliveries (Total of lines 18 thru 29)		110,233,814	
31	GAS LOSSES AND GAS UNACCOUNTED FOR			
32	Gas Losses and Gas Unaccounted For			
33	TOTALS			
34	Total Deliveries, Gas Losses & Unaccounted For (Total of lines 30 and 32)		110,233,814	