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

Form 1 Approved
OMB No. 1902-0021
(Expires 7/31/2008)
Form 1-F Approved
OMB No. 1902-0029
(Expires 6/30/2007)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 6/30/2007)

AVU-E

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IDAHO PUBLIC
UTILITIES COMMISSION

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

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

Exact Legal Name of Respondent (Company)	Year/Period of Report
Avista Corporation	End of 2007/Q4

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

IDENTIFICATION

01 Exact Legal Name of Respondent Avista Corporation	02 Year/Period of Report End of 2007/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 1411 East Mission Avenue, Spokane, WA, 99202	
05 Name of Contact Person M. K. Malquist	06 Title of Contact Person Executive VP and CFO
07 Address of Contact Person *(Street, City, State, Zip Code)* 1411 East Mission Avenue, Spokane, WA, 99202	

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(509) 495-8000	(1) ☒ An Original (2) ☐ A Resubmission	04/17/2008

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name	03 Signature	04 Date Signed *(Mo, Da, Yr)*
M. K. Malquist	MKMalquist	
02 Title Executive VP and CFO	M. K. Malquist	04/17/2008

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

LIST OF SCHEDULES (Electric Utility)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	NA
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Important Changes During the Year	108-109	
7	Comparative Balance Sheet	110-113	
8	Statement of Income for the Year	114-117	
9	Statement of Retained Earnings for the Year	118-119	
10	Statement of Cash Flows	120-121	
11	Notes to Financial Statements	122-123	
12	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
13	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
14	Nuclear Fuel Materials	202-203	NA
15	Electric Plant in Service	204-207	
16	Electric Plant Leased to Others	213	NA
17	Electric Plant Held for Future Use	214	NA
18	Construction Work in Progress-Electric	216	
19	Accumulated Provision for Depreciation of Electric Utility Plant	219	
20	Investment of Subsidiary Companies	224-225	
21	Materials and Supplies	227	
22	Allowances	228-229	NA
23	Extraordinary Property Losses	230	NA
24	Unrecovered Plant and Regulatory Study Costs	230	NA
25	Transmission Service and Generation Interconnection Study Costs	231	
26	Other Regulatory Assets	232	
27	Miscellaneous Deferred Debits	233	
28	Accumulated Deferred Income Taxes	234	
29	Capital Stock	250-251	
30	Other Paid-in Capital	253	NA
31	Capital Stock Expense	254	
32	Long-Term Debt	256-257	
33	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
34	Taxes Accrued, Prepaid and Charged During the Year	262-263	
35	Accumulated Deferred Investment Tax Credits	266-267	
36	Other Deferred Credits	269	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	NA
38	Accumulated Deferred Income Taxes-Other Property	274-275	
39	Accumulated Deferred Income Taxes-Other	276-277	
40	Other Regulatory Liabilities	278	
41	Electric Operating Revenues	300-301	
42	Sales of Electricity by Rate Schedules	304	
43	Sales for Resale	310-311	
44	Electric Operation and Maintenance Expenses	320-323	
45	Purchased Power	326-327	
46	Transmission of Electricity for Others	328-330	
47	Transmission of Electricity by ISO/RTOs	331	NA
48	Transmission of Electricity by Others	332	
49	Miscellaneous General Expenses-Electric	335	
50	Depreciation and Amortization of Electric Plant	336-337	
51	Regulatory Commission Expenses	350-351	
52	Research, Development and Demonstration Activities	352-353	NA
53	Distribution of Salaries and Wages	354-355	
54	Common Utility Plant and Expenses	356	
55	Amounts included in ISO/RTO Settlement Statements	397	NA
56	Purchase and Sale of Ancillary Services	398	
57	Monthly Transmission System Peak Load	400	
58	Monthly ISO/RTO Transmission System Peak Load	400a	NA
59	Electric Energy Account	401	
60	Monthly Peaks and Output	401	
61	Steam Electric Generating Plant Statistics	402-403	
62	Hydroelectric Generating Plant Statistics	406-407	
63	Pumped Storage Generating Plant Statistics	408-409	NA
64	Generating Plant Statistics Pages	410-411	
65	Transmission Line Statistics Pages	422-423	
66	Transmission Lines Added During the Year	424-425	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Substations	426-427	
68	Footnote Data	450	

Stockholders' Reports Check appropriate box:

[X] Four copies will be submitted

[ ] No annual report to stockholders is prepared

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

GENERAL INFORMATION

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

M. K. Malquist, Executive Vice President and Chief Financial Officer
1411 E. Mission Avenue
Spokane, WA 99202

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

State of Washington, Incorporated March 15, 1889

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not Applicable

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Electric service in the states of Washington, Idaho and Montana

Natural gas service in the states of 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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Avista Capital, Inc.	Parent company to the	100	
2		Company's subsidiaries.		
3				
4	Advantage IQ, Inc.	Provider of utility bill	93.3	Subsidiary of
5		processing, payment and		Avista Capital
6		information services to multi		
7		site customers in North Amer.		
8				
9	Avista Communications, Inc.	Inactive	100	Inactive
10				Subsidiary of
11				Avista Capital
12				
13				
14				
15				
16	Avista Development, Inc.	Maintains an investment	100	Subsidiary of
17		portfolio of real estate and		Avista Capital
18		other investments.		
19				
20				
21	Avista Energy, Inc.	Wholesale electricity and	100	Subsidiary of
22		natural gas trading,marketing		Avista Capital
23		and resource management.		
24		Majority of operations sold		
25		effective June 30, 2007.		
26				
27	Avista Laboratories, Inc.	Held a cost based investment	100	Inactive subsidiary

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

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1		in a fuel cell technology		or Avista Capital.
2		company. Inactive.		
3				
4	Avista Power, LLC	Owns non-regulated generation	100	Affiliate of
5		assets.		Avista Capital
6				
7	Avista Turbine Power, Inc.	Receives assignments of	100	Subsidiary of
8		purchase power agreements.		Avista Capital
9				
10	Avista Rathdrum, LLC	Owned 49 percent of Rathdrum	100	Inactive affiliate
11		Power, LLC (sold 10/2006)		of Avista Power.
12				
13	Avista Ventures, Inc.	Invests in emerging business.	100	Subsidiary of
14				Avista Capital
15				
16				
17	Pentzer Corporation	Parent company of Bay Area	100	Subsidiary of
18		Manufacturing and Pentzer		Avista Capital
19		Venture Holdings.		
20				
21	Advanced Manufacturing and Development, Inc.	Performs custom sheet metal	83	Subsidiary of
22	dba Metalfx	manufacturing of electronic		Bay Area
23		enclosures, parts and systems		Manufacturing.
24		for the computer, telecom and		
25		medical industries. AM&D		
26		also has a wood products		
27		division.		

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1				
2	Avista Receivables Corporation	Acquires and sells accounts	100	Subsidiary of
3		receivable of Avista Corp.		Avista Corp.
4				
5	Avista Energy Canada, Ltd.	A wholly owned subsidiary of	100	Subsidiary of
6		Avista Energy, Inc. that		Avista Energy
7		provided natural gas service		
8		to commercial and industrial		
9		customers in		
10		British Columbia, Canada.		
11		Majority of operations sold		
12		effective June 30, 2007.		
13				
14	Coyote Springs 2, LLC	Owned an interest in a	100	Inactive
15		generation plant.		
16				
17				
18	Spokane Energy, LLC	Marketing of energy.	100	Affiliate of
19				Avista Corp.
20				
21				
22	Avista Capital II	An affiliated business trust	100	Affiliate of
23		formed by the Company.		Avista Corp.
24		Issued Pref. Trust Securities		
25				
26	AVA Capital Trust III	An affiliated business trust	100	Affiliate of
27		formed by the Company.		Avista Corp.

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

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Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1		Issued Pref. Trust Securities		
2				
3	Steam Plant Square, LLC	Commercial office and retail	90	Subsidiary of
4		leasing.		Avista Development
5				
6	Courtyard Office Center	Commercial office and retail	100	Subsidiary of
7		leasing.		Avista Development
8				
9	AVA Formation Corp.	Holding Company	100	Formed in 2006 for th
10				purpose of completing
11				proposed statutory
12				share exchange and
13				holding company
14				structure. Currently
15				a subsidiary of
16				Avista Corp.
17				
18	Bay Area Manufacturing	Holding Company	100	Subsidiary of
19				Pentzer Corporation
20				
21	Pentzer Venture Holdings	Inactive	100	Subsidiary of
22				Pentzer Corporation
23				
24				
25				
26				
27				

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	Chairman of the Board and Chief Executive Officer	G. Ely	
2	(Retired 12/31/07)		
3			
4	Executive Vice President and Chief Financial Officer	M. K. Malquist	
5			
6	President and Chief Operating Officer	S. L. Morris	
7	(Chairman of the Board and CEO 01/01/08)		
8			
9	Vice President and Chief Counsel for Regulatory and	D. J. Meyer	
10	Governmental Affairs		
11			
12	Vice President, with responsibility for	R. R. Peterson	
13	Energy Resources (Retired 08/01/07)		
14			
15	Vice President, with responsibility for	R. D. Woodworth	
16	Business Development		
17			
18	Senior Vice President and Corporate Secretary	K. S. Feltes	
19	with responsibility for Human Resources		
20			
21	Vice President, Controller & Principal	C. M. Burmeister - Smith	
22	Accounting Officer (title change effective 05/11/07)		
23			
24	Vice President with responsibility for Transmission	D. F. Kopczynski	
25	and Distribution Operations		
26			
27	Vice President, with responsibility for State and	K. O. Norwood	
28	Federal Regulation		
29			
30	Senior Vice President, General Counsel and Chief	M. M. Durkin	
31	Compliance Officer		
32			
33	Vice President and Treasurer	A. M. Wilson	
34	(title change effective 05/11/07)		
35			
36	Vice President with responsibility for	D. P. Vermillion	
37	Energy Resources (hired from Avista Energy 07/02/07)		
38			
39	Vice President and Chief Information Officer	J.M. Kensok	
40	(effective 01/01/07)		
41			
42			
43			
44			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

DIRECTORS

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

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Scott L. Morris**	1411 E Mission Ave., Spokane, WA, 99202
2	(Chairman & CEO, as of 01/01/08)	
3		
4	Lura J. Powell	1009 Country Ct., Richland, WA 99352
5		
6	R. John Taylor***	111 Main Street, Lewiston ID 83501
7		
8	John F. Kelly	142 Isla Dorado Blvd., Coral Gables, FL 33143
9		
10	Jack W. Gustavel ***	1260 Riverstone Dr., 3rd Floor, Coeur d' Alene, ID 83814
11		
12	Heidi B. Stanley	111 N. Wall St., Spokane, WA 99201
13		
14	Erik J. Anderson	3720 Carillon Point, Kirkland, WA 98033
15		
16	Kristianne Blake***	P.O. Box 28338, Spokane, WA 99228
17		
18	Gary G. Ely	1411 E. Mission Ave, Spokane, WA 99202
19	(Chairman & CEO, retired 12/31/07)	
20		
21	Roy Lewis Eiguren	702 W. Idaho St., Suite 1000, Boise, ID 83702
22		
23	Michael L. Noel	11960 W. Six Shooter Rd. , Prescott, AZ 86305
24		
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 106, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

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

1. None
2. None
3. On June 30, 2007, Avista Energy, Inc. (a subisidiary of Avista Capital, which is a subsidiary of Avista Corp.) and Avista Energy Canada, Ltd. (a subsidiary of Avista Energy, Inc.) completed the sale of substantially all of their contracts and ongoing operations to Shell Energy North America (U.S.), L.P. (Shell Energy), formerly known as Coral Energy Holding, L.P., as well as to certain other subsidiaries of Shell Energy.
4. None
5. None
6. Avista Receivables Corporation (ARC) is a wholly owned, bankruptcy-remote subsidiary of Avista Corp., formed for the purpose of acquiring or purchasing interests in certain accounts receivable, both billed and unbilled, of the Company. On March 19, 2007, Avista Corp., ARC and a third-party financial institution amended a Receivables Purchase Agreement. The most significant amendment was to extend the termination date from March 20, 2007 to March 17, 2008. Under the Receivables Purchase Agreement, ARC can sell without recourse, on a revolving basis, up to $85.0 million of those receivables. ARC is obligated to pay fees that approximate the purchaser's cost of issuing commercial paper equal in value to the interests in receivables sold. The amount of such fees is included in other operating expenses of Avista Corp. The Receivables Purchase Agreement has financial covenants, which are substantially the same as those of Avista Corp.'s $320.0 million committed line of credit. As of December 31, 2007, there were $85 million of accounts receivables sold under this revolving agreement.
7. No changes in articles of incorporation or amendments to charter. On May 11, 2007, the Bylaws of Avista Corp. were amended. Specifically, section 4 of Article III of the Bylaws of Avista Corp. was changed to allow special meetings of the Board of Directors to be called by the Lead Director as well as by the Chairman, President, Executive Vice President or any three directors. Section 4 of Article III, which previously stated: "Special meetings of the Board of Directors may be called by or at the request of the Chairman of the Board, the President, the Executive Vice President or any three (3) directors. Notice of any special meeting shall be given to each director at least two (2) days in advance of the meeting." has been amended to state: "Special meetings of the Board of Directors may be called by or at the request of the Chairman of the Board, the President, the Executive Vice President, the Lead Director or any three (3) directors. Notice of any special meeting shall be given to each director at least two (2) days in advance of the meeting."
8. Average annual wage increases were 2.6% for non-exempt employees effective March 1, 2007. Average annual wage increases were 3.5% for exempt employees effective March 1, 2007. Average annual wage increases were 4.5% for officers effective March 1, 2007. Certain bargaining unit employees received increases ranging from 2.0% to 3.5% effective in March and April 2007.
9. Reference is made to Note 24 of the Notes to Financial Statements, page 123 of this Report.
10. None
11. Reserved
12. See page 123 of this Report.
13. Gary G. Ely, Chairman of the Board and Chief Executive Officer of Avista Corp., retired from the Company and the board, effective December 31, 2007. The Company's board of directors appointed Scott L. Morris, President and Chief Operating Officer of Avista Corp., to serve as a director on the board effective February 2007. The Company's board of directors also elected Mr. Morris to the positions of Chairman of the Board and Chief Executive Officer of Avista Corp., effective January 1, 2008.

In January 2007, James M. Kensok was appointed Vice President and Chief Information Officer.

Ronald R. Peterson, Vice President of Avista Corp. and Vice President of Energy Resources and Optimization of Avista Utilities retired from the Company on August 1, 2007. Dennis Vermillion, President and Chief Operating Officer of Avista Energy, was named Vice President of Energy Resources and Optimization of Avista Utilities effective upon the closing of the sale of the contracts and ongoing operations of Avista Energy to Coral Energy (June 30, 2007).

On May 11, 2007, the Board of Directors of Avista Corp. appointed Ann Wilson as Vice President and Treasurer and Christy Burmeister-Smith as Vice President, Controller and Principal Accounting Officer. Ann Wilson previously was Vice President and Controller of the Company since January 2006 and Vice President and Controller of Avista

Energy, Inc., from January 2000 to January 2006. Christy Burmeister-Smith previously was Vice President and Treasurer of the Company since January 2006 and Vice President and Controller of the Company from June 1999 to January 2006.

On February 15, 2008, Ann Wilson was appointed Vice President of Finance and Treasurer.

On February 15, 2008, the Board of Directors appointed Brian W. Dunham to serve as a director on the board effective March 1, 2008. Mr. Dunham is the president and chief executive officer of Northwest Pipe Company, which manufactures welded steel water transmission lines. Mr. Dunham will stand for election to the board at the annual meeting of shareholders on May 8, 2008.

On February 15, 2008, Lura J. Powell provided notification to Avista Corp. that she will not stand for re-election to the board when her term expires in May 2008 to focus on her professional commitments in technology and healthcare.

14. Proprietary capital is not less than 30 percent.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	3,131,916,272	2,938,456,395
3	Construction Work in Progress (107)	200-201	75,679,838	89,177,799
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		3,207,596,110	3,027,634,194
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	1,090,037,407	1,024,356,307
6	Net Utility Plant (Enter Total of line 4 less 5)		2,117,558,703	2,003,277,887
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		2,117,558,703	2,003,277,887
15	Utility Plant Adjustments (116)	122	0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		4,670,595	4,670,391
19	(Less) Accum. Prov. for Depr. and Amort. (122)		897,192	878,680
20	Investments in Associated Companies (123)		13,903,000	13,903,000
21	Investment in Subsidiary Companies (123.1)	224-225	71,371,272	247,190,561
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		28,691,550	31,166,335
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		15,878,558	13,360,954
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		55,312,881	25,574,531
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		188,930,664	334,987,092
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		5,264,119	-3,021,873
36	Special Deposits (132-134)		5,668,267	4,042,325
37	Working Fund (135)		679,537	684,345
38	Temporary Cash Investments (136)		2,608,103	667,445
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		87,238,080	89,325,500
41	Other Accounts Receivable (143)		9,920,307	9,714,601
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		2,965,676	2,730,352
43	Notes Receivable from Associated Companies (145)		0	7,198,865
44	Accounts Receivable from Assoc. Companies (146)		502,535	1,465,217
45	Fuel Stock (151)	227	2,213,923	2,121,931
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	17,365,306	14,019,070
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	0	0
55	Gas Stored Underground - Current (164.1)		13,414,238	11,905,320
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	1,006,819
57	Prepayments (165)		6,438,702	6,467,948
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	4,259
60	Rents Receivable (172)		509,924	327,042
61	Accrued Utility Revenues (173)		0	0
62	Miscellaneous Current and Accrued Assets (174)		6,153,636	162,032
63	Derivative Instrument Assets (175)		67,390,448	36,402,843
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		55,312,881	25,574,531
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		167,088,568	154,188,806
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		11,576,174	17,931,388
70	Extraordinary Property Losses (182.1)	230	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230	0	0
72	Other Regulatory Assets (182.3)	232	281,620,776	323,816,436
73	Prelim. Survey and Investigation Charges (Electric) (183)		234,518	8,645,616
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		0	8,046
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	40,642,265	31,297,127
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		20,965,705	28,622,766
82	Accumulated Deferred Income Taxes (190)	234	90,823,103	55,602,315
83	Unrecovered Purchased Gas Costs (191)		2,374,110	18,275,674
84	Total Deferred Debits (lines 69 through 83)		448,236,651	484,199,368
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		2,921,814,586	2,976,653,153

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Rresubmission	04/17/2008	end of 2007/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	727,945,794	722,039,406
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	2,281,868	0
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	3,294,916	6,419,099
11	Retained Earnings (215, 215.1, 216)	118-119	221,313,566	168,082,338
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	-14,672,673	51,109,032
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-19,607,486	-17,965,585
16	Total Proprietary Capital (lines 2 through 15)		913,966,153	916,846,092
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	671,733,175	685,196,931
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	114,603,000	115,203,000
21	Other Long-Term Debt (224)	256-257	273,010,231	311,600,402
22	Unamortized Premium on Long-Term Debt (225)		248,733	257,617
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		1,328,472	1,709,479
24	Total Long-Term Debt (lines 18 through 23)		1,058,266,667	1,110,548,471
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		75,206	394,921
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		344,000	954,409
29	Accumulated Provision for Pensions and Benefits (228.3)		90,554,881	102,083,620
30	Accumulated Miscellaneous Operating Provisions (228.4)		1,826,000	0
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		1,899,098	10,174,378
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		10,501,880	5,144,457
34	Asset Retirement Obligations (230)		3,990,011	4,809,738
35	Total Other Noncurrent Liabilities (lines 26 through 34)		109,191,076	123,561,523
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	4,000,000
38	Accounts Payable (232)		114,760,498	112,367,144
39	Notes Payable to Associated Companies (233)		2,182,637	0
40	Accounts Payable to Associated Companies (234)		600,647	980,544
41	Customer Deposits (235)		6,331,722	6,463,634
42	Taxes Accrued (236)	262-263	-4,717,808	-4,887,161
43	Interest Accrued (237)		12,577,801	11,594,861
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		252	2,651
48	Miscellaneous Current and Accrued Liabilities (242)		41,016,254	63,245,923
49	Obligations Under Capital Leases-Current (243)		295,029	281,894
50	Derivative Instrument Liabilities (244)		21,148,085	83,652,834
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		1,899,098	10,174,378
52	Derivative Instrument Liabilities - Hedges (245)		10,501,880	5,144,457
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		10,501,880	5,144,457
54	Total Current and Accrued Liabilities (lines 37 through 53)		192,296,019	267,527,946
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		1,265,933	1,087,069
57	Accumulated Deferred Investment Tax Credits (255)	266-267	423,036	472,344
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	18,072,332	17,616,522
60	Other Regulatory Liabilities (254)	278	65,481,339	18,246,960
61	Unamortized Gain on Reaquired Debt (257)		3,528,194	3,282,969
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		320,049,323	305,474,214
64	Accum. Deferred Income Taxes-Other (283)		239,274,514	211,989,043
65	Total Deferred Credits (lines 56 through 64)		648,094,671	558,169,121
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		2,921,814,586	2,976,653,153

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/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.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	1,321,662,326	1,319,860,703		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	965,325,057	957,162,716		
5	Maintenance Expenses (402)	320-323	45,512,775	41,805,328		
6	Depreciation Expense (403)	336-337	81,802,514	77,637,110		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	6,738,444	6,717,177		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	99,047	99,047		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		2,979,998	1,637,368		
13	(Less) Regulatory Credits (407.4)		8,618,156	17,989,452		
14	Taxes Other Than Income Taxes (408.1)	262-263	72,443,295	69,881,930		
15	Income Taxes - Federal (409.1)	262-263	22,447,987	39,535,123		
16	- Other (409.1)	262-263	520,211	1,155,970		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	12,026,706	4,330,636		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	4,122,957	11,112,169		
19	Investment Tax Credit Adj. - Net (411.4)	266	-49,308	-49,308		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)					
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,197,105,613	1,170,811,476		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		124,556,713	149,049,227		

STATEMENT OF INCOME FOR THE YEAR (Continued)

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

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		Line No.
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	
						1
744,131,553	797,555,083	577,530,773	522,305,620			2
						3
467,293,942	514,013,824	498,031,115	443,148,892			4
37,501,902	34,489,049	8,010,873	7,316,279			5
64,517,110	61,477,791	17,285,404	16,159,319			6
						7
5,686,773	5,912,961	1,051,671	804,216			8
99,047	99,047					9
						10
						11
337,368	337,368	2,642,630	1,300,000			12
7,499,030	17,989,452	1,119,126				13
46,412,373	45,176,981	26,030,922	24,704,949			14
14,193,471	28,758,428	8,254,516	10,776,695			15
378,906	847,436	141,305	308,534			16
13,472,601	9,067,991	-1,445,895	-4,737,355			17
3,382,861	9,689,311	740,096	1,422,858			18
		-49,308	-49,308			19
						20
						21
						22
						23
						24
639,011,602	672,502,113	558,094,011	498,309,363			25
105,119,951	125,052,970	19,436,762	23,996,257			26

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		124,556,713	149,049,227		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)					
33	Revenues From Nonutility Operations (417)					
34	(Less) Expenses of Nonutility Operations (417.1)		4,477,623	8,756,573		
35	Nonoperating Rental Income (418)		-18,512	-19,127		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	-4,595,749	16,839,461		
37	Interest and Dividend Income (419)		7,743,889	11,267,952		
38	Allowance for Other Funds Used During Construction (419.1)		4,736,330	2,429,542		
39	Miscellaneous Nonoperating Income (421)					
40	Gain on Disposition of Property (421.1)		257,380	237,712		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		3,645,715	21,998,967		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		2,289,978	138,153		
44	Miscellaneous Amortization (425)	340	1,110,572	1,120,288		
45	Donations (426.1)	340	622,859	1,368,086		
46	Life Insurance (426.2)		2,557,490	1,972,456		
47	Penalties (426.3)		37,600	5,500		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,097,891	1,052,120		
49	Other Deductions (426.5)		3,799,017	1,059,980		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		11,515,407	6,716,583		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	251,464	153,385		
53	Income Taxes-Federal (409.2)	262-263	149,939	584,900		
54	Income Taxes-Other (409.2)	262-263	-404,584	-912,325		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	-257,145	1,874,146		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	4,052,315	3,087,684		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-4,312,641	-1,387,578		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-3,557,051	16,669,962		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		69,538,504	77,938,550		
63	Amort. of Debt Disc. and Expense (428)		1,063,487	1,020,316		
64	Amortization of Loss on Reaquired Debt (428.1)		5,290,891	6,729,883		
65	(Less) Amort. of Premium on Debt-Credit (429)		8,885	8,884		
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)	340	7,605,326	7,116,429		
68	Other Interest Expense (431)	340	2,899,617	2,724,805		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		3,864,363	2,934,769		
70	Net Interest Charges (Total of lines 62 thru 69)		82,524,577	92,586,330		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		38,475,085	73,132,859		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		38,475,085	73,132,859		

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STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		166,534,217	130,475,915
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5	Tax Benefit Received from 401(k) Dividend Reinvestment Plan		-14,870	415,237
6	Dividends Received from Subsidiaries		48,260,105	5,989,256
7	Prior Period Adjustment for Benefit Plan Restatement		-2,471,138	
8	Stock Compensation Dividend Adjustment		15,913	
9	TOTAL Credits to Retained Earnings (Acct. 439)		45,790,010	6,404,493
10				
11	Stock Options Exercised			(160,637)
12	Preferred Series K Reclass		-1,334,004	
13	Debt Repurchase Adjustment		-4,392,647	
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)		-5,726,651	(160,637)
16	Balance Transferred from Income (Account 433 less Account 418.1)		43,070,834	56,293,398
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31			-31,450,517	(27,924,168)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-31,450,517	(27,924,168)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		1,547,552	1,445,216
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		219,765,445	166,534,217

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39			1,548,121	1,548,121
40				
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)		1,548,121	1,548,121
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)			
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		1,548,121	1,548,121
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		221,313,566	168,082,338
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		51,109,032	41,804,777
50	Equity in Earnings for Year (Credit) (Account 418.1)		-4,595,749	16,839,461
51	(Less) Dividends Received (Debit)		48,260,105	5,989,256
52	Subsidiary Expense & Misc Subs Equity Comp		-12,925,851	(1,545,950)
53	Balance-End of Year (Total lines 49 thru 52)		-14,672,673	51,109,032

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	38,475,085	73,132,859
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	88,540,958	84,354,287
5	Amortization of deferred power and natural gas costs	19,629,891	56,326,822
6	Amortization of debt expense	6,345,495	7,741,314
7	Amortization of investment in exchange power	2,450,030	2,450,031
8	Deferred Income Taxes (Net)	4,003,423	-16,465,046
9	Investment Tax Credit Adjustment (Net)	-49,308	-49,308
10	Net (Increase) Decrease in Receivables	1,881,714	11,519,009
11	Net (Increase) Decrease in Inventory	-3,940,327	203,045
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-28,529,359	-8,118,183
14	Net (Increase) Decrease in Other Regulatory Assets	-8,395,908	-6,061,549
15	Net Increase (Decrease) in Other Regulatory Liabilities	1,888,830	-1,175,736
16	(Less) Allowance for Other Funds Used During Construction	4,736,330	2,429,542
17	(Less) Undistributed Earnings from Subsidiary Companies	-4,595,749	16,839,461
18	Other (provide details in footnote):	696,571	-2,476,259
19	Write-down of asset	2,289,978	
20	Change in other noncurrent assets and liabilities	-2,782,552	-8,672,181
21	Net change in receivables allowance	235,324	-497,564
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	122,599,264	172,942,538
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-196,772,585	-156,952,633
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction		
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-196,772,585	-156,952,633
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		657,770
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies	170,364,287	36,646,304
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans	17,967	15,263
48			
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
54	Changes in other property and investments	-2,942,625	-763,324
55	Proceeds from sale of utility property claim		5,483,780
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-29,332,956	-114,912,840
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		149,778,000
62	Preferred Stock		
63	Common Stock	4,977,331	88,393,784
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	4,977,331	238,171,784
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-26,156,580	-197,231,550
74	Preferred Stock	-26,250,000	-1,750,000
75	Common Stock		
76	Premiums paid for the redemption of long-term debt		-425,996
77	Long-term debt and short-term borrowing issuance costs	-164,700	-5,435,618
78	Net Decrease in Short-Term Debt (c)	-4,000,000	-59,000,000
79	Cash paid in interest rate swap agreement		-3,738,000
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-31,450,517	-27,927,206
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-83,044,466	-57,336,586
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	10,221,842	693,112
87			
88	Cash and Cash Equivalents at Beginning of Period	-1,670,083	-2,363,195
89			
90	Cash and Cash Equivalents at End of period	8,551,759	-1,670,083

NOTES TO FINANCIAL STATEMENTS

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

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SEE PAGE 123 FOR REQUIRED INFORMATION.

NOTES TO FINANCIAL STATEMENTS

NOTE 1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Business
Avista Corporation (Avista Corp. or the Company) is an energy company engaged in the generation, transmission and distribution of 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 western 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 northeast and southwest Oregon. Avista Capital, Inc. (Avista Capital), a wholly owned subsidiary of Avista Corp., is the parent company of all of the subsidiary companies in the non-utility business segments including Avista Energy, Inc. (Avista Energy) and Advantage IQ, Inc. (Advantage IQ). Avista Energy was an electricity and natural gas marketing, trading and resource management business. On June 30, 2007, Avista Energy completed the sale of substantially all of its contracts and ongoing operations. Advantage IQ is a provider of facility information and cost management services for multi-site customers throughout North America.

The Company's operations are exposed to risks including, but not limited to:

- streamflow and weather conditions that impact hydroelectric generation, utility operations and customer demand,
- market prices and supply of wholesale energy, which the Company purchases and sells, including power, fuel and natural gas,
- regulatory disallowance of the recovery of power and natural gas costs, operating costs and capital investments,
- the effects of changes in legislative and governmental regulations, including restrictions on emissions from generating plants and requirements for the acquisition of new resources,
- changes in regulatory requirements,
- availability of generation facilities,
- competition, and
- availability of funding at a reasonable cost.

Also, like other utilities, the Company's facilities and operations are exposed to terrorism risks or other malicious acts. In addition, the energy business exposes the Company to the financial, liquidity, credit and price risks associated with wholesale purchases and sales of energy commodities.

Basis of Reporting
The financial statements include the assets, liabilities, revenues and expenses of the Company. As required by the Federal Energy Regulatory Commission (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 accounting principles generally accepted in the United States of America. 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 accounting principles generally accepted in the United States of America in the presentation of (1) current portions of long-term debt, short-term borrowings, and preferred stock, (2) assets and liabilities for cost of removal of assets, (3) assets held for sale, (4) regulatory assets and liabilities, (5) retained earnings, 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 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,
- stock-based compensation, and
- unbilled revenues.

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

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

Regulation
The Company is subject to state regulation in Washington, Idaho, Montana and Oregon. The Company is also subject to federal regulation by the FERC.

Operating Revenues
Revenues related to the sale of energy are generally 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 $16.1 million (net of $57.2 million of unbilled receivables sold) as of December 31, 2007 and $21.7 million (net of $51.6 million of unbilled receivables sold) as of December 31, 2006. See Note 5 for information related to the sale of accounts receivable.

Advertising Expenses
The Company expenses advertising costs as incurred. Advertising expenses were not a material portion of the Company's operating expenses in 2007, 2006 and 2005.

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 $51.0 million in 2007, $48.3 million in 2006 and $43.1 million in 2005.

Income Taxes
The Company accounts for income taxes under Statement of Financial Accounting Standards (SFAS) No. 109, "Accounting for Income Taxes." Under SFAS No. 109, a deferred 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 tax expense for the period is equal to the net change in the deferred tax asset and liability accounts from the beginning to the end of the period. The effect on deferred taxes of a change in tax rates is recognized in income in the period that includes the enactment date. Deferred tax liabilities and regulatory assets are established for tax benefits flowed through to customers as prescribed by the respective regulatory commissions.

Stock-Based Compensation
Prior to January 1, 2006, the Company followed the disclosure only provisions of SFAS No. 123, "Accounting for Stock-Based Compensation." Accordingly, employee stock options were accounted for under Accounting Principle Board Opinion (APB) No. 25, "Accounting for Stock Issued to Employees." Stock options were granted at exercise prices not less than the fair value of common stock on the date of grant. Avista Corp. has not granted any stock options since 2003. Under APB No. 25, no compensation expense was recognized pursuant to the Company's stock option plans. However, the Company recognized compensation expense related to performance-based share awards. The Company adopted SFAS No. 123R, "Share-Based Payment," on January 1, 2006, which resulted in changes to stock compensation expense recognition. See Note 23 for further information. The Company adopted SFAS No. 123R using the modified prospective method and, accordingly, the financial statements for prior periods presented were not restated to reflect the fair value method of recognizing compensation expense relating to share-based payments.

If compensation expense for the Company's stock-based employee compensation plans were determined consistent with SFAS No. 123, net income and earnings per common share would be the following pro forma amounts for the year ended December 31, 2005 (prior to the adoption of SFAS No. 123R):

	2005
Net income (dollars in thousands):	
As reported	$44,988
Add: Total stock-based employee compensation expense included in net income, net of tax	2,211
Deduct: Total stock-based employee compensation expense determined under the fair value method for all awards, net of tax	(2,911)
Pro forma	$44,288
Basic and diluted earnings per common share:	
Basic as reported	$0.93
Diluted as reported	$0.92
Basic pro forma	$0.91
Diluted pro forma	$0.90

Earnings Per Common Share

Basic earnings per common share is computed by dividing income available for common stock by the weighted average number of common shares outstanding for the period. Diluted earnings per common share is calculated by dividing income available for common stock by diluted weighted average common shares outstanding during the period, including common stock equivalent shares outstanding using the treasury stock method, unless such shares are anti-dilutive. Common stock equivalent shares include shares issuable upon exercise of stock options and contingent stock awards. See Note 22 for earnings per common share calculations.

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. Cash and cash equivalents include cash deposits from counterparties. See Note 7 for further information related to cash deposits from counterparties.

Allowance for Doubtful Accounts

The Company maintains an allowance for doubtful accounts to provide for estimated and potential losses on accounts receivable. The Company determines the allowance for utility and other customer accounts receivable based on historical write-offs as compared to accounts receivable and operating revenues. Additionally, the Company establishes specific allowances for certain individual accounts. The following table presents the activity in the allowance for doubtful accounts during the years ended December 31 (dollars in thousands):

	2007	2006	2005
Allowance as of the beginning of the year	$2,730	$3,228	$2,810
Additions expensed during the year	3,078	2,888	2,752
Net deductions	(2,842)	(3,386)	(2,334)
Allowance as of the end of the year	$2,966	$2,730	$3,228

Materials and Supplies, Fuel Stock and Natural Gas Stored

Inventories of materials and supplies, fuel stock and natural gas stored are recorded at the lower of cost or market, primarily using the average cost method.

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. Costs of depreciable units of property retired plus costs of removal less salvage are charged to accumulated depreciation.

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. In accordance with the uniform system of accounts prescribed by regulatory authorities, AFUDC is capitalized as a part of the cost of utility plant and the debt related portion is credited currently against total interest expense in the Statements of Income. The Company generally is permitted, under established regulatory rate practices, to recover the capitalized AFUDC, and a fair 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 generally does not occur until the related utility plant is placed in service and included in rate base. The effective AFUDC rate was 9.11 percent in 2007 and 2006 and 9.72 percent for 2005. The Company's AFUDC rates do not exceed the maximum allowable rates as determined in accordance with the requirements of regulatory authorities.

Depreciation
For utility operations, depreciation expense is estimated by a method of depreciation accounting utilizing unit rates for generation plants and composite rates for other utility plant. Such rates are designed to provide for retirements of properties at the expiration of their service lives. The rates for hydroelectric plants include annuity and interest components, in which the interest component is 9 percent. For utility operations, the ratio of depreciation provisions to average depreciable property was 2.89 percent in 2007, 2.89 percent in 2006 and 2.93 percent in 2005.

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

- electric thermal production - 28 years,
- hydroelectric production - 77 years,
- electric transmission - 45 years,
- electric distribution - 48 years, and
- natural gas distribution property - 37 years.

Regulatory Deferred Charges and Credits
The Company prepares its financial statements in accordance with the provisions of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." The Company prepares its financial statements in accordance with SFAS No. 71 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.

SFAS No. 71 requires the Company to reflect the impact of regulatory decisions in its financial statements. SFAS No. 71 requires that certain costs and/or obligations (such as incurred power and natural gas costs not currently recovered through rates, but expected to be recovered in the future) are reflected as deferred charges or credits on the Balance Sheets. These costs and/or obligations are not reflected in the statement 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 SFAS No. 71 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.

The Company's primary regulatory assets include:

- power and natural gas deferrals,
- investment in exchange power,
- regulatory asset for deferred income taxes,
- unamortized debt expense,
- assets offsetting net utility energy commodity derivative liabilities (see Note 6 for further information),
- expenditures for demand side management programs,
- expenditures for conservation programs, and
- unfunded pensions and other postretirement benefits.

Regulatory liabilities include:

- liabilities created when the Centralia Power Plant was sold,
- liabilities offsetting net utility energy commodity derivative assets (see Note 6 for further information), and
- the gain on the general office building sale/leaseback.

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 Washington Utilities and Transportation Commission (WUTC) 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 beginning 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, as well as premiums paid to repurchase debt, which are amortized over the remaining life of the original debt that was repurchased or, if new debt is issued in connection with the repurchase, these costs are amortized over the life of the new debt. These costs are recovered through retail rates as a component of interest expense. Pursuant to a settlement agreement in its Washington general rate case in 2007, Avista Corp. agreed to write off $3.8 million of unamortized debt repurchase costs. See Note 4 for further details.

Power Cost Deferrals and Recovery Mechanisms

Deferred power supply costs are recorded as a deferred charge on the Balance Sheets for future review and recovery through retail rates. The power supply costs deferred include certain differences between actual power supply costs incurred by Avista Corp. and the costs included in base retail rates. This difference in power supply costs primarily results from changes in:

- short-term wholesale market prices,
- 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 increase or decrease electric rates periodically with WUTC approval to reflect changes in power supply costs. The ERM is an accounting method used to track certain differences between actual power supply costs and the amount included in base retail rates for Washington customers. Avista Corp. accrues interest on deferred power costs in the Washington jurisdiction at a rate, which is adjusted semi-annually, of 7.8 percent as of December 31, 2007. Total deferred power costs for Washington customers were $58.5 million as of December 31, 2007 and $70.2 million as of December 31, 2006.

The initial amount of power supply costs in excess or below the level in retail rates, which the Company either incurs the cost of, or receives the benefit from, 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. As such, 50 percent of the annual power supply cost variance in this range is deferred for future surcharge or rebate to customers and the Company incurs the cost of, or receives the benefit from, the remaining 50 percent. 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 incurs the cost of, or receives the benefit from, 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 to the Company
+/- $0 - $4 million	0%	100%
+/- between $4 million - $10 million	50%	50%
+/- excess over $10 million	90%	10%

Avista Corp. has a power cost adjustment (PCA) mechanism in Idaho that allows it to modify electric rates periodically 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. In June 2007, the IPUC approved continuation of the PCA mechanism with the annual rate adjustment provision. The October 1 rate adjustments recover or rebate power costs deferred during the preceding, July-June, twelve-month period. Avista Corp. accrues interest on deferred power costs in the Idaho jurisdiction at a rate, which is adjusted annually, of 5.0 percent as of December 31, 2007. Total deferred power costs for Idaho customers were $21.2 million as of December 31, 2007 and $9.4 million as of December 31, 2006.

Natural Gas Cost Deferrals and Recovery Mechanisms

In the fall of each year, 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 for the prior year, 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 were $2.4 million (an asset of $6.2 million and a liability of $3.8 million) as of December 31, 2007 and $18.3 million as of December 31, 2006.

NOTE 2. NEW ACCOUNTING STANDARDS

Effective January 1, 2006, the Company adopted SFAS No. 123R, "Share-Based Payment," which supersedes APB No. 25 and SFAS No. 123 and their related implementation guidance. This statement established revised standards for the accounting for transactions in which the Company exchanges its equity instruments for goods or services with a primary focus on transactions in which the Company obtains employee services in share-based payment transactions. The statement requires that the compensation cost relating to share-based payment transactions be recognized in financial statements based on the fair value of the equity or liability instruments issued. The Company implemented the provisions of this statement using the modified prospective method and, accordingly, financial statements for prior periods presented were not restated to reflect the fair value method of recognizing compensation expense relating to share-based payments. Under the modified prospective approach, SFAS 123R applied to all of the Company's unvested stock-based payment awards beginning January 1, 2006 and all prospective awards. In addition, SFAS No. 123R requires the Company to classify tax benefits resulting from tax deductions in excess of stock-based compensation expense recognized as a financing activity. This amount is not significant to cash flows and is included in the line item proceeds from issuance of common stock on the Statement of Cash Flows. See Note 23 for further information related to stock compensation plans.

Effective January 1, 2007, the Company adopted Financial Accounting Standards Board (FASB) Interpretation No. 48, "Accounting for Uncertainty in Income Taxes-an Interpretation of FASB Statement No. 109," (FIN 48) which provides guidance for the recognition and measurement of a tax position taken or expected to be taken in a tax return. FIN 48 requires the evaluation of a tax position as a two-step process. First, the Company is required to determine whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. If the tax position meets the "more likely than not" recognition threshold, it is then measured and recorded at the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. The adoption of FIN 48 did not have a cumulative effect on the Company's financial statements. See Note 11 for further information.

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements," which provides enhanced guidance for using fair value to measure assets and liabilities. This statement also expands disclosures about fair value measurements. This statement applies under other accounting pronouncements that require or permit fair value measurements. However, the statement does not require any new fair value measurements. This statement emphasizes that fair value is a market-based measurement and not an entity-specific measurement. Therefore a fair value measurement should be determined based on the assumptions that market participants would use in pricing an asset or liability. The statement establishes a fair value hierarchy that prioritizes the information used to develop those assumptions giving the highest priority to quoted prices in active markets and the lowest priority to unobservable data. The Company will be required to adopt SFAS No. 157 in 2008. The Company does not expect SFAS No. 157 to have a material impact on its financial condition and results of operations. However, the Company will have expanded disclosures with respect to fair value measurements.

Effective December 31, 2006, SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans – an amendment of FASB Statements No. 87, 88, 106, and 132 (R)" required the Company to recognize the overfunded or underfunded status of defined benefit postretirement plans in the Company's Balance Sheet measured as the difference between the fair value of plan assets and the benefit obligation. For a pension plan, the benefit obligation is the projected benefit obligation; for any other postretirement benefit plans, the benefit obligation is the accumulated postretirement benefit obligation. Previously, the Company only recognized the underfunded status of defined benefit pension plans as the difference between the fair value of plan assets and the accumulated benefit obligation. As the Company has historically recovered and currently recovers its pension and other postretirement benefit costs related to its regulated operations in retail rates, the Company records a regulatory asset for that portion of its pension and other postretirement benefit funding deficiency. As such, the underfunded status of the Company's pension and other postretirement benefit plans under SFAS No. 158 resulted in the recognition as of December 31, 2006 of:

- a liability of $60.1 million (associated deferred taxes of $21.0 million) for pensions and other postretirement benefits,
- a regulatory asset of $54.2 million (associated deferred taxes of $19.0 million) for pensions and other postretirement benefits,
- an increase to accumulated other comprehensive loss of $3.7 million (net of taxes of $2.1 million), and
- the removal of the intangible pension asset of $3.7 million (was included in other deferred charges).

As such, the total effect on the deferred income tax liability for the adoption of SFAS No. 158 was a net decrease of $2.1 million. The adoption of this statement did not have any effect on the Company's net income.

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities." This statement permits entities to choose to measure many financial assets and financial liabilities at fair value. Unrealized gains and losses on items for which the fair value option is elected would be reported in net income. The Company will be required to adopt SFAS No. 159 in 2008. The Company does not plan to use the fair value option under SFAS No. 159 and as such does not expect SFAS No. 159 to impact its financial condition and results of operations.

In December 2007, the FASB issued SFAS No. 141(R), "Business Combinations." This statement replaces SFAS No. 141 and addresses the accounting for all transactions or other events in which an entity obtains control of one or more businesses. This statement requires the acquiring entity in a business combination to recognize the assets acquired, the liabilities assumed, and any noncontrolling interest in the transaction at the acquisition date, measured at their fair values as of that date, with limited exceptions. The Company will be required to begin applying this statement to any business combinations in 2009.

In December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements." This statement amends Accounting Research Bulletin No. 51, "Consolidated Financial Statements" to establish accounting and reporting standards from noncontrolling (minority) interest in a subsidiary and for the deconsolidation of a subsidiary. This statement clarifies that a noncontrolling interest in a subsidiary is an ownership in the consolidated entity that should be reported as equity in the consolidated financial statements. The Company will be required to adopt SFAS No. 160 in 2009. The Company is evaluating the impact SFAS No. 160 will have on its financial condition and results of operations.

NOTE 3. DISPOSITION OF AVISTA ENERGY

On June 30, 2007, Avista Energy and Avista Energy Canada completed the sale of substantially all of their contracts and ongoing operations to Shell Energy North America (U.S.), L.P. (Shell Energy), formerly known as Coral Energy Holding, L.P., as well as to certain other subsidiaries of Shell Energy.

As consideration for the assets acquired (net of liabilities assumed), the purchase price paid by Shell Energy was calculated on the closing date as the sum of the following:

- the net trade book value of contracts acquired,
- the market value of the natural gas inventory, and
- the net book value of the tangible fixed assets acquired.

Proceeds from the transaction included cash consideration for the net assets acquired by Shell Energy and the liquidation of the remaining net current assets of Avista Energy not sold to Shell Energy (primarily receivables, restricted cash and deposits with counterparties).

Assets and liabilities excluded from the sale and retained or liquidated by Avista Energy include:

- cash,
- certain agreements, including electric transmission, natural gas transportation and a power purchase agreement, related to a 270 MW natural gas-fired combined cycle combustion turbine plant located in Idaho (Lancaster Plant), for periods after December 31, 2009 through 2026,
- storage rights at a natural gas facility located in Washington (Jackson Prairie) for periods after April 30, 2011,
- accounts receivable,
- accounts payable,

- tax obligations,
- cash deposits with and from counterparties,
- litigation matters (including matters related to western energy markets), and
- certain employment agreements and employee related obligations.

Certain assets of Avista Energy with a net book value of approximately $30 million have not been liquidated. These primarily include natural gas storage and deferred tax assets. The Company expects that the natural gas storage will ultimately be transferred to Avista Corp., subject to future regulatory approval. The Company also expects that the power purchase agreement for the Lancaster Plant for the period 2010 through 2026 will be transferred to Avista Corp., subject to future regulatory approval.

In connection with the transaction, on June 30, 2007, Avista Energy and its affiliates entered into an Indemnification Agreement with Shell Energy and its affiliates. Under the Indemnification Agreement, Avista Energy and Shell Energy each agree to provide indemnification of the other and the other's affiliates for certain events and matters described in the purchase and sale agreement entered into on April 16, 2007 and certain other transaction agreements. Such events and matters include, but are not limited to, the refund proceedings arising out of the western energy markets in 2000 and 2001 (see Note 24), existing litigation, tax liabilities, matters with respect to storage rights at Jackson Prairie, and any potential issues associated with the power purchase agreement for the Lancaster Plant. In general, such indemnification is not required unless and until a party's claims exceed $150,000 and is limited to an aggregate amount of $30 million and a term of three years (except for agreements or transactions with terms longer than three years). These limitations do not apply to certain third party claims.

Avista Energy's obligations under the Indemnification Agreement are guaranteed by Avista Capital pursuant to a Guaranty dated June 30, 2007. This Guaranty is limited to an aggregate amount of $30 million plus certain fees and expenses. Avista Capital granted Shell Energy a security interest in 50 percent of Avista Capital's common shares of Advantage IQ as collateral for its Guaranty. The aggregate obligations secured by this security interest will in no event exceed $25 million. Avista Capital may substitute collateral, such as cash or letters of credit, in place of the security interest in Advantage IQ's common shares. This security interest in Advantage IQ's common shares will terminate in 18 months (December 31, 2008) except to the extent of claims actually made prior to expiration of the 18-month period. The Guaranty will terminate April 30, 2011 except with respect to claims made prior to termination.

As of February 25, 2008, there have not been any claims under the Indemnification Agreement or Guaranty.

Avista Energy made customary representations, warranties and covenants in the purchase and sale agreement. Avista Corp. and its subsidiaries agreed that for a period of 60 calendar months beginning on the closing of the transaction (June 30, 2007), neither Avista Corp. nor any of its subsidiaries will form or participate through ownership or any alliance, or internally, develop capabilities to replicate the business activities of Avista Energy within the region of the Western Electric Coordinating Council. This restriction has certain exceptions primarily related to any assets or contracts retained by Avista Energy and any current corporate activities outside of Avista Energy, including any resource optimization or associated trading or hedging activities of the character currently being conducted by Avista Corp. in the ordinary course of its regulated utility business (see Note 6).

NOTE 4. IMPAIRMENT OF ASSETS

During the third quarter of 2007, the Company recorded an impairment charge of $2.3 million for a turbine and related equipment. The Company originally planned to use the turbine in a regulated utility generation project. At the end of the third quarter of 2007, the Company reached a conclusion to sell the turbine and related equipment, which were classified as assets held for sale as of December 31, 2007. The impairment charge reduced the carrying value of the assets to the estimated fair value.

Pursuant to a settlement agreement in its Washington general rate case entered into in October 2007 and approved by the WUTC in December 2007, Avista Corp. agreed to write off $3.8 million of unamortized debt repurchase costs. These costs were for premiums paid to repurchase debt prior to its scheduled maturity. In accordance with regulatory accounting practices, these premiums were recorded as a regulatory asset in unamortized debt expense on the Balance Sheet and were being amortized over the average remaining maturity of outstanding debt.

NOTE 5. ACCOUNTS RECEIVABLE SALE

Avista Receivables Corporation (ARC) is a wholly owned, bankruptcy-remote subsidiary of Avista Corp. formed for the purpose of acquiring or purchasing interests in certain accounts receivable, both billed and unbilled, of the Company. On March 19, 2007, Avista Corp., ARC and a third-party financial institution amended a Receivables Purchase Agreement. The most significant amendment extended the termination date from March 20, 2007 to March 17, 2008. Under the Receivables Purchase Agreement, ARC can sell without recourse, on a revolving basis, up to $85.0 million of those receivables. ARC is obligated to pay fees that approximate the purchaser's cost of issuing commercial paper equal in value to the interests in receivables sold. The amount of such fees is included in other operating expenses of Avista Corp. The Receivables Purchase Agreement has financial covenants, which are substantially the same as those of Avista Corp.'s $320.0 million committed line of credit (see Note 13). At each of December 31, 2007 and 2006, $85.0 million in accounts receivables were sold under this revolving agreement.

NOTE 6. ENERGY COMMODITY TRADING

The Company is exposed to risks relating to, but not limited to:

- changes in certain commodity prices, and
- counterparty performance.

Avista Corp. utilizes derivative instruments, such as forwards, futures, swaps and options in order to manage the various risks relating to these exposures. The Company uses a variety of techniques to manage risks for their energy resources and wholesale energy market activities. The Company has a risk management policy and control procedures to manage these risks, both qualitative and quantitative. The Company's Risk Management Committee establishes the Company's risk management policy and control procedures and monitors compliance. The Risk Management Committee is comprised of certain Company officers and other individuals and is overseen by the Audit Committee of the Company's Board of Directors.

Avista Corp. engages in an ongoing process of resource optimization, which involves the economic selection from available resources to serve Avista Corp.'s load obligations and uses its existing resources to capture available economic value. Avista Corp. sells and purchases wholesale electric capacity and energy and fuel as part of the process of acquiring resources to serve its load obligations. These transactions range from terms of one hour up to multiple years. Avista Corp. makes continuing projections of:

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

On the basis of these projections, Avista Corp. makes purchases and sales of energy to match expected resources to expected electric load requirements. Resource optimization involves generating plant dispatch and scheduling available resources and also includes transactions such as:

- purchasing fuel for generation,
- when economic, selling fuel and substituting wholesale purchases for the operation of Avista Corp.'s resources, and
- other wholesale transactions to capture the value of generation and transmission resources.

Avista Corp.'s optimization process includes entering into hedging transactions to manage risks.

As part of its resource optimization process described above, Avista Corp. manages the impact of fluctuations in electric energy prices by measuring and controlling the volume of energy imbalance between projected loads and resources and through the use of derivative commodity instruments for hedging purposes. Load/resource imbalances within a rolling 18-month planning horizon are compared against established volumetric guidelines and management determines the timing and specific actions to manage the imbalances. Management also assesses available resource decisions and actions that are appropriate for longer-term planning periods.

SFAS No. 133, as amended, establishes accounting and reporting standards for derivative instruments, including certain derivative instruments embedded in other contracts, and for hedging activities. It requires the recording of all derivatives as either assets or liabilities on the balance sheet measured at estimated fair value and the recognition of the unrealized gains and losses. 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.

Avista Corp. enters into forward contracts to purchase or sell electricity and natural gas. Under these forward contracts, Avista Corp. commits to purchase or sell a specified amount of energy at a specified time, or during a specified period, in the future. Certain of these forward contracts are considered derivative instruments. Avista Corp. also records derivative commodity assets and liabilities for over-the-counter and exchange-traded derivative instruments as well as certain long-term contracts. These contracts are entered into as part of Avista Corp.'s management of its loads and resources as discussed above. In conjunction with the issuance of SFAS No. 133, the WUTC and the IPUC issued accounting orders authorizing Avista Corp. to offset any 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 and the PCA mechanism.

Substantially all forward contracts to purchase or sell power and natural gas are recorded as assets or liabilities at market value with an offsetting regulatory asset or liability. Contracts that are not considered derivatives under SFAS No. 133 are generally accounted for at cost 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.

Market Risk

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. Market risk is influenced to the extent that the performance or nonperformance by market participants of their contractual obligations and commitments affect the supply of, or demand for, the commodity. The Company manages the market risks inherent in their activities according to the risk management policy established by the Company's Risk Management Committee.

Credit Risk

Credit risk relates to the risk of loss 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 they may not be able to collect amounts owed to them. Changes in market prices may dramatically alter the size of credit risk with counterparties, even when conservative credit limits are established. Credit risk includes the risk that a counterparty may 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.

Should a counterparty, customer or supplier fail to perform, the Company may be required to honor the underlying commitment or to replace existing contracts with contracts at then-current market prices. The Company seeks to mitigate credit risk by:

- entering into bilateral contracts that specify credit terms and protections against default,
- applying specific eligibility criteria to existing and prospective counterparties, and
- actively monitoring current credit exposures.

These credit policies include an evaluation of the financial condition and credit ratings of counterparties, collateral requirements or other credit enhancements, such as letters of credit or parent company guarantees. The Company also uses standardized agreements that allow for the netting or offsetting of positive and negative exposures associated with a single counterparty.

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

- electric utilities,
- electric generators and transmission providers,
- natural gas producers and pipelines, 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, either positively or negatively, because the counterparties may be similarly affected by changes in conditions.

Credit risk also involves the exposure that counterparties perceive related to the ability of the Company to perform deliveries and settlement under physical and financial energy contracts. These counterparties may seek assurances of performance in the form of letters of credit, prepayment, or cash deposits.

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 minimize capital requirements.

Other Operational and Event Risks

In addition to market and credit risk, the Company is subject to operational and event risks including, among others:

- blackouts or disruptions to transmission or transportation systems,
- forced outages at generating plants,
- fuel quality and availability,
- disruptions to information systems and other administrative resources required for normal operations, and
- weather conditions and natural disasters that can cause physical damage to property, requiring repairs to restore utility service.

Terrorism and other malicious threats are a risk to the entire utility industry. Potential disruptions to operations or destruction of facilities from terrorism or other malicious acts are not readily determinable. The Company has taken various steps to mitigate terrorism risks and prepare contingency plans in the event that its facilities are targeted.

NOTE 7. CASH DEPOSITS WITH AND FROM COUNTERPARTIES

Cash deposits from counterparties totaled $12.5 million as of December 31, 2007 and $39.4 million as of December 31, 2006. These funds were held by Avista Corp. to mitigate the potential impact of counterparty default risk. These amounts are subject to return if conditions warrant because of continuing portfolio value fluctuations with those parties or substitution of non-cash collateral.

As is common industry practice, Avista Corp. maintains margin agreements with certain counterparties. Margin calls are triggered when exposures exceed predetermined 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. From time to time, margin calls are made and/or received by Avista Corp. Negotiating for collateral in the form of cash, letters of credit, or performance guarantees is common industry practice.

NOTE 8. 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 was $329.6 million and accumulated depreciation was $197.7 million as of December 31, 2007.

NOTE 9. ASSET RETIREMENT OBLIGATIONS

The Company follows SFAS No. 143, "Accounting for Asset Retirement Obligations," and 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):

	2007	2006	2005
Asset retirement obligation at beginning of year	$4,810	$4,529	$1,191
New liability recognized	-	-	3,243
Liability adjustment due to revision in estimated cash flows	(1,063)	-	-
Liability settled	(71)	(51)	(28)
Accretion expense	314	332	123
Asset retirement obligation at end of year	$3,990	$4,810	$4,529

NOTE 10. PENSION PLANS AND OTHER POSTRETIREMENT BENEFIT PLANS

The Company has a defined benefit pension plan covering substantially all regular full-time employees. Individual benefits under this plan are based upon the employee's years of service 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 $15 million in cash to the pension plan in each of 2007, 2006 and 2005. The Company expects to contribute at least $15 million to the pension plan in 2008.

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 $15.2 million in 2008, $15.5 million in 2009, $16.2 million in 2010, $16.7 million in 2011 and $17.8 million in 2012. For the ensuing five years (2013 through 2017), the Company expects that benefit payments under the pension plan and the SERP will total $110.0 million.

The Finance Committee of the Company's Board of Directors:

- establishes investment policies, objectives and strategies that seek an appropriate return for the pension plan, and
- reviews and approves changes to the investment and funding policies.

The Company has contracted with an investment consultant who is responsible for managing/monitoring the individual investment managers. The investment managers' performance and related individual fund performance is periodically reviewed by the Finance Committee to ensure 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 Finance Committee has established investment allocation percentages by asset classes as indicated in the table in this Note.

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. The market-related value of pension plan assets invested in debt and equity securities was based primarily on fair value (market prices).

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

- current cost of reproducing a property less deterioration and functional economic obsolescence,
- capitalization of the property's net earnings power, and
- value indicated by recent sales of comparable properties in the market.

The market-related value of plan assets was determined as of December 31, 2007 and 2006.

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.

In 2006, the form of payment election assumption was analyzed based upon historical trends and future projections. The Company revised the form of payment election to assume that 5 percent of retirees and 50 percent of vested terminated participants will elect a lump sum payment, based upon the analysis. The form of payment election assumption previously assumed that 50 percent of retirees and vested terminated participants would elect a lump sum payment. The change resulted in an increase of $13.2 million to the pension benefit obligation as of December 31, 2006. The change also increases future years' pension costs.

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 twenty years, beginning in 1993. The Company expects that benefit payments under the postretirement benefit plan will be $3.1 million in 2008, $3.0 million in 2009, $2.9 million in 2010, $2.8 million in 2011 and $2.7 million in 2012. For the ensuing five years (2013 through 2017), the Company expects that benefit payments under the postretirement benefit plan will total $12.3 million. The Company expects to contribute $3.1 million to the postretirement benefit plan in 2008, representing expected benefit payments to be paid during the year.

The Company established 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 employees' 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. Effective December 31, 2007, this plan was amended to eliminate a provision that allowed an executive officer to elect for their beneficiaries to receive one quarter of such payment each year over a ten-year period commencing within 30 days of the executive officer's death. The plan was also amended to provide that those who become executive officers after December 31, 2007 will no longer be eligible to receive benefits after retirement. The amendments to the plan reduced the benefit obligation by $1.6 million.

The Company uses a December 31 measurement date for its pension and postretirement plans. The following table sets forth the pension and other postretirement plan disclosures as of December 31, 2007 and 2006 and the components of net periodic benefit costs for the years ended December 31, 2007, 2006 and 2005 (dollars in thousands):

	Pension		Other Postretirement	
	2007	2006	2007	2006
Change in benefit obligation:				
Benefit obligation as of beginning of year	$315,691	$301,746	$33,632	$32,710
Service cost	10,694	9,963	672	639
Interest cost	19,161	17,158	2,159	1,956
Plan amendment	-	-	(1,601)	-
Actuarial loss (gain)	(5,245)	2,524	2,612	1,914
Transfer of accrued vacation	-	-	585	-
Benefits paid	(16,912)	(15,521)	(3,707)	(3,557)
Expenses paid	(299)	(179)	-	(30)
Benefit obligation as of end of year	$323,090	$315,691	$34,352	$33,632
Change in plan assets:				
Fair value of plan assets as of beginning of year	$225,079	$199,163	$20,878	$18,378
Actual return on plan assets	18,799	25,737	1,840	2,530
Employer contributions	15,000	15,000	-	-
Benefits paid	(16,018)	(14,642)	-	-
Expenses paid	(299)	(179)	-	(30)
Fair value of plan assets as of end of year	$242,561	$225,079	$22,718	$20,878
Funded status	$(80,529)	$(90,612)	$(11,634)	$(12,754)
Unrecognized net actuarial loss	62,174	69,679	4,472	2,084
Unrecognized prior service cost	3,098	3,751	(1,600)	-
Unrecognized net transition obligation	-	-	2,526	3,031
Accrued benefit cost	(15,257)	(17,182)	(6,236)	(7,639)
Additional liability	(65,272)	(73,430)	(5,398)	(5,115)
Accrued benefit liability	$(80,529)	$(90,612)	$(11,634)	$(12,754)

Accumulated pension benefit obligation	$275,159	$264,647	-	-
Accumulated postretirement benefit obligation:				
For retirees			$18,572	$20,351
For fully eligible employees			$9,675	$7,169
For other participants			$6,105	$6,112
Included in accumulated comprehensive loss (income) (net of tax):				
Unrecognized net transition obligation	$ -	$ -	$1,642	$1,970
Unrecognized prior service cost	2,013	2,438	(1,040)	-
Unrecognized net of net actuarial loss	40,414	45,291	2,907	1,358
Total	42,427	47,729	3,509	3,328
Less regulatory asset	(28,560)	(31,992)	(4,594)	(3,233)
Accumulated other comprehensive loss (income)	$13,867	$15,737	$(1,085)	$ 95
Weighted-average asset allocations as of December 31:				
Equity securities	49%	53%	62%	64%
Debt securities	31%	28%	38%	33%
Real estate	6%	5%	-	-
Other	14%	14%	-	3%
Target asset allocations as of December 31:				
Equity securities	39-61%	39-61%	52-72%	52-72%
Debt securities	27-33%	27-33%	28-48%	28-48%
Real estate	3-7%	3-7%	-	-
Other	10-22%	10-22%	-	-
Weighted average assumptions as of December 31:				
Discount rate for benefit obligation	6.34%	6.15%	6.20%	6.15%
Discount rate for annual expense	6.15%	5.75%	6.15%	5.75%
Expected long-term return on plan assets	8.50%	8.50%	8.50%	8.50%
Rate of compensation increase	4.66%	4.84%		
Medical cost trend pre-age 65 – initial			9.00%	9.00%
Medical cost trend pre-age 65 – ultimate			5.00%	5.00%
Ultimate medical cost trend year pre-age 65			2012	2011
Medical cost trend post-age 65 – initial			9.00%	9.00%
Medical cost trend post-age 65 – ultimate			6.00%	6.00%
Ultimate medical cost trend year post-age 65			2011	2010

	2007	2006	2005	2007	2006	2005
Components of net periodic benefit cost:						
Service cost	$10,694	$ 9,963	$ 9,480	$ 672	$ 639	$ 654
Interest cost	19,161	17,158	16,228	2,159	1,956	1,839
Expected return on plan assets	(19,217)	(16,997)	(15,917)	(1,775)	(1,562)	(1,368)
Transition (asset)/obligation recognition	-	-	(499)	505	505	505
Amortization of prior service cost	653	653	654	-	-	-
Net loss recognition	2,978	3,772	3,442	193	90	-
Net periodic benefit cost	$14,269	$14,549	$13,388	$1,754	$1,628	$1,630

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, 2007 by $1.6 million and the service and interest cost by $0.2 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, 2007 by $1.4 million and the service and interest cost by $0.1 million.

The Company and its most significant subsidiaries have salary deferral 401(k) plans that are defined contribution plans and cover substantially all employees. Employees can make contributions to their respective accounts in the plans on a pre-tax basis up to the maximum amount permitted by law. The respective company matches a portion of the salary deferred by each participant according to the schedule in the respective plan. Employer matching contributions were $4.6 million in 2007, $4.4 million in 2006 and $4.1

million in 2005.

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. At December 31, 2007 and 2006, there were deferred compensation assets of $12.1 million and $12.6 million included in other special funds and corresponding deferred compensation liabilities of $12.1 million and $12.6 million included in other deferred credits on the Balance Sheets.

NOTE 11. 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.

The realization of deferred 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 tax assets and determined it is more likely than not that deferred tax assets will be realized.

As disclosed in Note 2, the Company adopted FIN 48 effective January 1, 2007, which did not have a cumulative effect on the Company's financial statements.

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, Montana and California. Subsidiaries are charged or credited with the tax effects of their operations on a stand-alone basis. The Internal Revenue Service (IRS) has examined the Company's 2001, 2002 and 2003 federal income tax returns. Despite those tax years still remaining open, all issues were resolved with the exception of the timing for the deductions of certain indirect overhead costs. The IRS is currently conducting an examination of the Company's 2004 and 2005 federal income tax returns. This examination could result in a change in the liability for uncertain tax positions. However, an estimate of the range of any such possible change cannot be made at this time. The Company does not believe that any open tax years with respect to state income taxes could result in any adjustments that would be significant to the financial statements.

In August 2005, the Treasury Department issued regulations and the IRS issued a revenue ruling that affects the tax treatment by Avista Corp. of certain indirect overhead expenses. Avista Corp. had previously made a tax election to currently deduct certain indirect overhead costs, starting with the 2002 tax return, that were capitalized for financial accounting purposes. This election allowed Avista Corp. to take tax deductions resulting in a total reduction of approximately $40 million in current tax liabilities for 2002, 2003 and 2004. These current tax benefits were deferred on the balance sheet in accordance with the provisions of SFAS No. 109 and did not affect net income.

Due to the revenue ruling and related regulations, the IRS has disallowed the tax deduction of indirect overhead expenses during their examination of the Company's 2001, 2002 and 2003 federal income tax returns. The Company believes that the tax deductions claimed on tax returns were appropriate based on the applicable statutes and regulations in effect at the time. Avista Corp. appealed the proposed IRS adjustment on April 19, 2006. The Company's appeal is being reviewed by the IRS Appeals Division. The Company repaid a portion of the previous tax deductions through tax payments in 2005 and 2006. There can be no assurance that the Company's position will prevail. However, it is not expected to have a significant effect on the Company's net income.

The Company estimates that its liability for unrecognized tax benefits is $22.6 million at each of January 1, 2007 and December 31, 2007. This liability primarily relates to the indirect overhead expenses described above. The liability for unrecognized tax benefits would not affect the tax rate if recognized in 2007, as any adjustment to this tax item would be offset by an adjustment to current income tax expense. The liability for interest expense for unrecognized tax benefits as of January 1, 2007 was not material due to net operating loss and tax credit carryovers. The change in the liability for interest expense during 2007 was not material. The Company has not accrued any penalties. The Company would recognize interest accrued related to income tax positions as interest expense and any penalties incurred as other operating expense.

The Company had net regulatory assets of $117.5 million at December 31, 2007 and $105.9 million at December 31, 2006 related to the probable recovery of certain deferred tax liabilities from customers through future rates.

NOTE 12. 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, which are included in operation expenses in the Statements of Income, were $733.5 million in 2007, $682.5 million in 2006 and $652.2 million in 2005. 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):

	2008	2009	2010	2011	2012	Thereafter	Total
Power resources	$125,265	$120,493	$110,608	$ 78,163	$ 74,162	$ 395,936	$ 904,627
Natural gas resources	190,545	112,215	77,058	56,075	52,034	636,375	1,124,302
Total	$315,810	$232,708	$187,666	$134,238	$126,196	$1,032,311	$2,028,929

All of the energy purchase contracts were entered into as part of Avista Corp.'s obligation to serve its retail natural gas and electric customers' energy requirements. As a result, these costs are generally 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 expenses associated with these agreements are reflected as operation expenses and maintenance expenses in the Statements of Income. The following table details future contractual commitments for these agreements (dollars in thousands):

	2008	2009	2010	2011	2012	Thereafter	Total
Contractual obligations	$15,207	$15,234	$15,262	$15,291	$15,322	$167,144	$243,460

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. The cost of power obtained under the contracts, including payments made when a facility is not operating, is included in operation expenses in the Statements of Income. Expenses under these PUD contracts were $18.0 million in 2007, $13.1 million in 2006 and $9.0 million in 2005. Information as of December 31, 2007 pertaining to these PUD contracts is summarized in the following table (dollars in thousands):

	Company's Current Share of					
	Output	Kilowatt Capability	Annual Costs (1)	Debt Service Costs (1)	Bonds Outstanding	Expiration Date
Chelan County PUD:						
Rocky Reach Project	2.9%	37,000	$ 2,181	$1,007	$ 1,796	2011
Douglas County PUD:						
Wells Project	3.5%	30,000	1,891	795	4,506	2018
Grant County PUD:						
Priest Rapids Project	3.3%	55,000	9,534	882	10,064	2055
Wanapum Project	8.2%	75,000	4,430	2,949	18,526	2055
Totals		197,000	$18,036	$5,633	$34,892	

(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 the year 2007. 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):

	2008	2009	2010	2011	2012	Thereafter	Total
Minimum payments	$4,531	$4,554	$3,280	$3,210	$2,742	$41,265	$59,582

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

NOTE 13. COMMITTED LINE OF CREDIT

The Company has a committed line of credit agreement with various banks in the total amount of $320.0 million with an expiration date of April 5, 2011. Under the credit agreement, the Company can request the issuance of up to $320.0 million in letters of credit. Total letters of credit outstanding were $34.8 million as of December 31, 2007 and $77.1 million as of December 31, 2006. The committed line of credit is secured by $320.0 million of 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, including a covenant requiring the ratio of "earnings before interest, taxes, depreciation and amortization" to "interest expense" of Avista Corp. for the preceding twelve-month period at the end of any fiscal quarter to be greater than 1.6 to 1. As of December 31, 2007, the Company was in compliance with this covenant with a ratio of 2.70 to 1. The committed line of credit agreement also has a covenant which does not permit the ratio of "consolidated total debt" to "consolidated total capitalization" of Avista Corp. to be greater than 70 percent at the end of any fiscal quarter. As of December 31, 2007, the Company was in compliance with this covenant with a ratio of 53.8 percent. If the proposed change in organization becomes effective, the committed line of credit will remain at Avista Corp.

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 and for the years ended December 31 (dollars in thousands):

	2007	2006	2005
Balance outstanding at end of period	$ -	$ 4,000	$ 63,000
Maximum balance outstanding during the period	48,000	77,000	167,000
Average balance outstanding during the period	6,833	16,740	61,181
Average interest rate during the period	7.91%	6.07%	4.45%
Average interest rate at end of period	- %	8.25%	5.48%

NOTE 14. BONDS AND OTHER LONG-TERM DEBT

The following details the interest rate and maturity dates of bonds and other long-term debt outstanding as of December 31 (dollars in thousands):

Maturity Year	Description	Interest Rate	2007	2006
2007	Secured Medium-Term Notes	5.99%	$ -	$ 13,850
2008	Secured Medium-Term Notes	6.06%-6.95%	45,000	45,000
2010	Secured Medium-Term Notes	6.67%-8.02%	35,000	35,000
2012	Secured Medium-Term Notes	7.37%	7,000	7,000
2013	First Mortgage Bonds	6.13%	45,000	45,000
2018	Secured Medium-Term Notes	7.39%-7.45%	22,500	22,500
2019	First Mortgage Bonds	5.45%	90,000	90,000
2023	Secured Medium-Term Notes	7.18%-7.54%	13,500	13,500
2028	Secured Medium-Term Notes (1)	6.37%	25,000	25,000
2032	Secured Pollution Control Bonds (2)	5.00%	66,700	66,700
2034	Secured Pollution Control Bonds (2)	5.13%	17,000	17,000
2035	First Mortgage Bonds	6.25%	150,000	150,000
2037	First Mortgage Bonds	5.70%	150,000	150,000
	Total secured long-term debt		666,700	680,550
2007	Unsecured Medium-Term Notes	7.90%-7.94%	-	12,000
2008	Unsecured Senior Notes	9.75%	272,860	272,860
2023	Unsecured Pollution Control Bonds	6.00%	4,100	4,100
	Total unsecured long-term debt		276,960	288,960
	Interest rate swaps		1,083	1,037
	Committed line of credit		-	4,000
	Preferred stock		-	26,250
	Total bonds and other long-term debt		$944,743	$1,000,797

(1) These Secured Medium-Term Notes with a maturity date of June 2028 are puttable at the option of the security holders in June 2008.
(2) These Secured Pollution Control Bonds are subject to remarketing on December 30, 2008. These bonds are puttable at the option of the security holders on that date. If the bonds cannot be successfully remarketed on that date, the Company will be required to purchase the outstanding bonds.

The following table details future long-term debt maturities (2008 maturities include amounts discussed at (1) and (2) above), not including interest rate swaps (dollars in thousands):

Year	2008	2009	2010	2011	2012	Thereafter	Total
Debt maturities	$426,560	$ -	$35,000	$ -	$7,000	$475,100	$943,660

Substantially all utility properties owned by the Company are subject to the lien of the Company's various mortgage indentures. 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) 70 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; provided, however, that the Company may not issue any additional First Mortgage 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, an on all indebtedness of prior rank. As of December 31, 2007, property additions and retired bonds would have entitled the Company to issue $953.3 million in aggregate principal amount of additional First Mortgage Bonds. However, using an interest rate of 8 percent on additional First Mortgage Bonds, and based on net earnings for the 12 months ended December 31, 2007, the net earnings test would limit the principal amount of additional bonds the Company could issue to $609.5 million.

See Note 13 for information regarding First Mortgage Bonds issued to secure the Company's obligations under its $320.0 million committed line of credit.

NOTE 15. ADVANCES FROM ASSOCIATED COMPANIES

In 2004, the Company issued Junior Subordinated Debt Securities, with a principal amount of $61.9 million to AVA Capital Trust III, an affiliated business trust formed by the Company. Concurrently, AVA Capital Trust III issued $60.0 million of Preferred Trust Securities to third parties and $1.9 million of Common Trust Securities to the Company. All of these securities have a fixed interest rate of 6.50 percent for five years (through March 31, 2009). Subsequent to the initial five-year fixed rate period, the securities will either have a new fixed rate or an adjustable rate. These debt securities may be redeemed by the Company on or after March 31, 2009 and will mature on April 1, 2034.

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 annual distribution rate paid during 2007 ranged from 5.999 percent to 6.455 percent. As of December 31, 2007, the annual distribution rate was 5.999 percent. 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; however, this is limited by an agreement under the Company's 9.75 percent Senior Notes that mature on June 1, 2008. In December 2000, the Company purchased $10.0 million of these Preferred Trust Securities.

The Company has guaranteed the payment of distributions on, and redemption price and liquidation amount with respect to, the Preferred Trust Securities to the extent that AVA Capital Trust III and Avista Capital II have 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 16. INTEREST RATE SWAP AGREEMENTS

Avista Corp. enters into forward-starting interest rate swap agreements to manage the risk associated with changes in interest rates and the impact on future interest payments. These interest rate swap agreements relate to the interest payments for the anticipated issuances of debt. These interest rate swap agreements are considered hedges against fluctuations in future cash flows associated with changes in interest rates in accordance with SFAS No. 133.

In 2005, the Company cash settled an interest rate swap and received $4.4 million. In December 2006, Avista Corp. cash settled an interest rate swap agreement and paid $3.7 million. These settlements were deferred as regulatory items (part of long-term debt) and will be amortized over the remaining terms of the interest rate swap agreements (forecasted interest payments) in accordance with regulatory accounting practices.

Under the terms of the two outstanding interest rate swap agreements (totaling $125.0 million) as of December 31, 2007, the value of the interest rate swaps is determined based upon Avista Corp. paying a fixed rate and receiving a variable rate based on LIBOR for a term of ten years beginning in 2008. As of December 31, 2007, Avista Corp. had a long-term derivative liability of $10.5 million and a net unrealized loss of $6.8 million recorded as accumulated other comprehensive loss on the Balance Sheets. The interest rate swap agreements provide for mandatory cash settlement of these contracts in 2009. The amount included in accumulated other comprehensive income or loss at the cash settlement date will be reclassified to a regulatory asset or liability (part of long-term debt) in accordance with regulatory accounting practices under SFAS No. 71. This regulatory asset or liability will be amortized as a component of interest expense over the life of the forecasted interest payments.

NOTE 17. LEASES

The Company has multiple lease arrangements involving various assets, with minimum terms ranging from one to forty-five years. Rental expense under operating leases was $2.0 million in 2007, $2.5 million in 2006 and $8.0 million in 2005. Future minimum lease payments required under operating leases having initial or remaining noncancelable lease terms in excess of one year as of December 31, 2007 were as follows (dollars in thousands):

Year ending December 31:	2008	2009	2010	2011	2012	Thereafter	Total
Minimum payments required	$1,538	$1,380	$412	$201	$117	$2,798	$6,446

NOTE 18. GUARANTEES

The Company has guaranteed the payment of distributions on, and redemption price and liquidation amount with respect to, the Preferred Trust Securities issued by its affiliates, AVA Capital Trust III and Avista Capital II, to the extent that these entities have funds available for such payments from the respective debt securities.

Avista Power, through its equity investment in Rathdrum Power, LLC (RP LLC), was a 49 percent owner of the Lancaster Plant, which commenced commercial operation in September 2001. In October 2006, Avista Power completed the sale of its investment in RP LLC for close to book value. The output from the Lancaster Plant is contracted to Avista Energy through 2026 under a power purchase agreement. Avista Corp. has guaranteed the power purchase agreement for the performance of Avista Energy. The majority of the rights and obligations of this agreement were assigned to Shell Energy through the end of 2009. Beginning in 2010, the Company expects that these rights and obligations will be transferred to Avista Corp., subject to future approval.

In connection with the transaction, on June 30, 2007, Avista Energy and its affiliates entered into an Indemnification Agreement with Shell Energy and its affiliates. Under the Indemnification Agreement, Avista Energy and Shell Energy each agree to provide indemnification of the other and the other's affiliates for certain events and matters described in the purchase and sale agreement entered into on April 16, 2007 and certain other transaction agreements. Such events and matters include, but are not limited to, the refund proceedings arising out of the western energy markets in 2000 and 2001 (see Note 24), existing litigation, tax liabilities, matters with respect to storage rights at Jackson Prairie, and any potential issues associated with the power purchase agreement for the Lancaster Plant. In general, such indemnification is not required unless and until a party's claims exceed $150,000 and is limited to an aggregate amount of $30 million and a term of three years (except for agreements or transactions with terms longer than three years). These limitations do not apply to certain third party claims.

Avista Energy's obligations under the Indemnification Agreement are guaranteed by Avista Capital pursuant to a Guaranty dated June 30, 2007. This Guaranty is limited to an aggregate amount of $30 million plus certain fees and expenses. Avista Capital granted Shell Energy a security interest in 50 percent of Avista Capital's common shares of Advantage IQ as collateral for its Guaranty. The aggregate obligations secured by this security interest will in no event exceed $25 million. Avista Capital may substitute collateral, such as cash or letters of credit, in place of the security interest in Advantage IQ's common shares. This security interest in Advantage IQ's common shares will terminate in 18 months (December 31, 2008) except to the extent of claims actually made prior to expiration of the 18-month period. The Guaranty will terminate April 30, 2011 except with respect to claims made prior to termination.

NOTE 19. PREFERRED STOCK-CUMULATIVE (SUBJECT TO MANDATORY REDEMPTION)

The Company has 10 million authorized shares of $6.95 Series K preferred stock. In September 2007, the Company redeemed the 262,500 remaining outstanding shares of this preferred stock for $26.25 million. In each of September 2006 and 2005, the Company made mandatory redemptions of 17,500 shares of preferred stock for $1.75 million.

NOTE 20. FAIR VALUE OF FINANCIAL INSTRUMENTS

The carrying values of cash, special deposits, working funds, temporary cash investments, accounts and notes receivable, accounts payable and the committed line of credit are reasonable estimates of their fair values. Energy commodity derivative assets and liabilities, as well as derivatives related to interest rate swap agreements, are reported at estimated fair value on the Balance Sheets. The following table sets forth the estimated fair value and carrying value of the Company's long-term debt (including current portion, but excluding capital leases), long-term debt to affiliated trusts and preferred stock subject to mandatory redemption as of December 31, 2007 and 2006 (dollars in thousands):

	2007		2006	
	Carrying Value	Estimated Fair Value	Carrying Value	Estimated Fair Value
Long-term debt	$943,660	$969,899	$969,510	$976,548
Long-term debt to affiliated trusts	113,403	109,109	113,403	110,147
Preferred stock	-	-	26,250	26,622

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

NOTE 21. COMMON STOCK

In November 1999, the Company adopted a shareholder rights plan pursuant to which holders of common stock outstanding on February 15, 1999, or issued thereafter, were granted one preferred share purchase right (Right) on each outstanding share of common stock. Each Right, initially evidenced by and traded with the shares of common stock, entitles the registered holder to purchase one one-hundredth of a share of preferred stock of the Company, without par value, at a purchase price of $70, subject to certain adjustments, regulatory approval and other specified conditions. The Rights will be exercisable only if a person or group acquires 10 percent or more of the outstanding shares of common stock or commences a tender or exchange offer, the consummation of which would result in the beneficial ownership by a person or group of 10 percent or more of the outstanding shares of common stock. Upon any such acquisition, each Right will entitle its holder to purchase, at the purchase price, that number of shares of common stock or preferred stock of the Company (or, in the case of a merger of the Company into another person or group, common stock of the acquiring person or group) that has a market value at that time equal to twice the purchase price. In no event will the Rights be exercisable by a person that has acquired 10 percent or more of the Company's common stock. The Rights may be redeemed, at a redemption price of $0.01 per Right, by the Board of Directors of the Company at any time until any person or group has acquired 10 percent or more of the common stock. In connection with the proposed statutory share exchange (see Note 25), the shareholder rights plan was amended to provide that the Rights will expire upon the earlier of the effective time of the statutory share exchange or March 31, 2009 (the originally scheduled expiration date).

The Company has a Dividend Reinvestment and Stock Purchase 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 and long-term debt contained in the Company's Articles of Incorporation and various mortgage indentures. Covenants under the Company's 9.75 percent Senior Notes that mature in 2008 limit the Company's ability to increase its common stock cash dividend to no more than 5 percent over the previous quarter, unless certain conditions are met related to restricted payments. As of December 31, 2007, the Company met the conditions that would allow it to increase the common stock cash dividend in excess of 5 percent over the previous quarter.

In December 2006, the Company entered into a sales agency agreement with a sales agent, to issue up to 2 million shares of its common stock from time to time. As of February 25, 2008, the Company has not issued any shares under the sales agency agreement.

NOTE 22. EARNINGS PER COMMON SHARE

The following table presents the computation of basic and diluted earnings per common share for the years ended December 31 (in thousands, except per share amounts):

	2007	2006	2005
Numerator:			
Net income	$38,475	$72,941	$44,988
Subsidiary earnings adjustment for dilutive securities	(349)	-	-
Adjusted net income for computation of diluted earnings per common share	$38,126	$72,941	$44,988
Denominator:			
Weighted-average number of common shares outstanding-basic	52,796	49,162	48,523
Effect of dilutive securities:			
Contingent stock awards	168	371	198
Stock options	299	364	258
Weighted-average number of common shares outstanding-diluted	53,263	49,897	48,979
Total earnings per common share, basic	$0.73	$1.48	$0.93
Total earnings per common share, diluted	$0.72	$1.46	$0.92

Total stock options outstanding that were not included in the calculation of diluted earnings per common share were 303,950 for 2007, 26,200 for 2006 and 695,500 for 2005. These stock options were excluded from the calculation because they were antidilutive based on the fact that the exercise price of the stock options was higher than the average market price of Avista Corp. common stock during the respective period. In addition, contingent stock awards of 318,900 were outstanding as of December 31, 2005, which were not included in basic or diluted shares because the performance conditions were not satisfied.

NOTE 23. STOCK COMPENSATION PLANS

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 3.5 million shares of its common stock for grant under the 1998 Plan. As of December 31, 2007, 0.9 million shares were remaining for grant under this plan.

2000 Plan

In 2000, the Company adopted a Non-Officer Employee Long-Term Incentive Plan (2000 Plan), which was not required to be approved by shareholders. The provisions of the 2000 Plan are essentially the same as those under the 1998 Plan, except for the exclusion of non-employee directors and executive officers of the Company. The Company has available a maximum of 2.5 million shares of its common stock for grant under the 2000 Plan. However, the Company currently does not plan to issue any further options or securities under the 2000 Plan. As of December 31, 2007, 1.7 million shares were remaining for grant under this plan.

Stock Compensation

Prior to January 1, 2006, the Company accounted for stock based compensation using APB No. 25, which required the recognition of compensation expense on the excess, if any, of the market price of the stock at the date of grant over the exercise price of the option. As the exercise price for options granted under the 1998 and 2000 Plans was equal to the market price at the date of grant, there was no compensation expense recorded by the Company. However, the Company recognized compensation expense related to performance-based share awards. For periods presented prior to January 1, 2006, the Company is required to disclose pro forma net income and earnings per common share as if the Company had adopted the fair value method of accounting for stock-based compensation.

On January 1, 2006, the Company adopted SFAS No. 123R, which supersedes APB No. 25 and SFAS No. 123 and their related implementation guidance. The statement requires that the compensation cost relating to share-based payment transactions be recognized in financial statements based on the fair value of the equity or liability instruments issued. The Company adopted SFAS No. 123R using the modified prospective method and, accordingly, financial statement amounts for prior periods presented were not restated to reflect the fair value method of recognizing compensation expense relating to share-based payments. The Company recorded stock-based compensation expense of $2.5 million for 2007 and $4.0 million for 2006. The total income tax benefit recognized in the Statements of Income was $1.0 million for 2007 and $1.5 million for 2006.

Stock Options

The fair value of stock option awards was calculated using the Black Scholes option pricing model. This model requires the use of subjective assumptions, including stock price volatility, dividend yield, risk-free interest rate and expected time to exercise. See Note 1 for disclosure of pro forma net income and earnings per common share for 2005. The following summarizes stock options activity under the 1998 Plan and the 2000 Plan for the years ended December 31:

	2007	2006	2005
Number of shares under stock options:			
Options outstanding at beginning of year	1,541,045	2,095,211	2,332,198
Options granted	-	-	-
Options exercised	(123,134)	(504,452)	(192,377)
Options canceled	(6,000)	(49,714)	(44,610)
Options outstanding at end of year	1,411,911	1,541,045	2,095,211
Options exercisable at end of year	1,411,911	1,541,045	1,968,629
Weighted average exercise price:			
Options granted	$ -	$ -	$ -
Options exercised	$15.14	$16.12	$13.50
Options canceled	$26.59	$20.77	$20.42
Options outstanding at end of year	$15.38	$15.41	$15.68
Options exercisable at end of year	$15.38	$15.41	$16.03
Intrinsic value of options exercised (in thousands)	$1,022	$3,520	$956
Intrinsic value of options outstanding (in thousands)	$8,697	$15,256	$4,253

Information for options outstanding and exercisable as of December 31, 2007 was as follows:

Range of Exercise Prices	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Life (in years)
$10.17-$11.68	357,560	$10.29	4.7
$11.69-$14.61	372,775	11.82	3.8
$14.62-$17.53	243,501	17.04	2.2
$17.54-$20.45	134,125	18.76	1.1
$20.46-$26.29	283,750	22.56	2.7
$26.30-$28.47	20,200	27.63	2.2
Total	1,411,911	$15.38	3.3

Total cash received from the exercise of stock options was $1.9 million for 2007 and $9.9 million for 2006. As of December 31, 2007 and 2006, the Company's stock options were fully vested and expensed.

Restricted Shares

Restricted shares 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, 2007 was one year.

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

	2007	2006
Unvested shares at beginning of year	36,180	-
Shares granted	31,860	36,260
Shares cancelled	(19,936)	(80)
Shares vested	(19,967)	-
Unvested shares at end of year	28,137	36,180
Weighted average fair value at grant date	$25.60	$21.32
Unrecognized compensation expense at end of year (in thousands)	$517	$439
Intrinsic value, unvested shares at end of year (in thousands)	$606	$916
Intrinsic value, shares vested during the year (in thousands)	$461	$ -

Performance Shares

Performance share grants have vesting periods of three years. Performance 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 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. The performance condition used is the Company's Total Shareholder Return (TSR) performance over a three-year period as compared against other utilities; under SFAS 123R 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. Under Statement SFAS 123R, 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 granted in accordance with the provisions of SFAS No. 123R. 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 costs as well as the resulting estimated fair value of performance shares granted:

	2007	2006	2005
Risk-free interest rate	4.8%	4.6%	3.4%
Expected life, in years	3	3	3
Expected volatility	19.4%	21.9%	34.1%
Dividend yield	2.5%	2.9%	3.0%
Weighted average grant date fair value (per share)	$18.71	$18.08	$16.70

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

The following summarizes performance share activity:

	2007	2006	2005
Opening balance of unvested performance shares	300,406	318,331	308,145
Performance shares granted	114,640	138,710	163,600

Performance shares canceled	(45,632)	(1,404)	(500)
Performance shares vested	(161,573)	(155,231)	(152,914)
Ending balance of unvested performance shares	207,841	300,406	318,331
Intrinsic value of unvested performance shares (in thousands)	$4,477	$7,603	$5,638
Unrecognized compensation expense (in thousands)	$2,058	$2,400	$ -

The weighted average remaining vesting period for the Company's restricted shares outstanding as of December 31, 2007 was 1.4 years. Unrecognized compensation expense as of December 31, 2007 will be recognized during 2008 and 2009. The following summarizes the impact of the market condition on the vested performance shares:

	2007	2006	2005
Performance shares vested	161,573	155,231	152,914
Impact of market condition on shares vested	(56,551)	34,151	30,583
Shares of common stock earned	105,022	189,382	183,497
Intrinsic value of common stock earned (in thousands)	$2,262	$4,793	$3,250

In 2007, 2006 and 2005, the number of performance shares vested was adjusted by (35) percent, 22 percent and 20 percent due to the performance condition achieved. Shares earned under this plan are distributed to participants in the quarter following vesting.

Awards outstanding under the performance share grants include a dividend component that is paid in cash. This component of the performance share grants is accounted for as a liability award under the guidance of SFAS No. 123R. 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, 2007 and 2006, the Company had recognized compensation expense and a liability of $0.4 million and $0.7 million related to the dividend component of performance share grants.

NOTE 24. 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. With respect to these proceedings, 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. With respect to matters that affect Avista Corp.'s regulated utility operations, the Company intends to seek, to the extent appropriate, recovery of incurred costs through the rate making process. With respect to matters discussed in this Note that affect Avista Energy (particularly the California Refund Proceeding), any potential liabilities or refunds remain at Avista Corp. and/or its subsidiaries and were not assumed by Shell Energy and/or its affiliates.

Federal Energy Regulatory Commission Inquiry

On April 19, 2004, the FERC issued an order approving the contested Agreement in Resolution of Section 206 Proceeding (Agreement in Resolution) reached by Avista Corp., Avista Energy and the FERC's Trial Staff with respect to an investigation into the activities of Avista Corp. and Avista Energy in western energy markets during 2000 and 2001. In the Agreement in Resolution, the FERC Trial Staff stated that its investigation found: (1) no evidence that any executives or employees of Avista Corp. or Avista Energy knowingly engaged in or facilitated any improper trading strategy; (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) that Avista Corp. and Avista Energy did not withhold relevant information from the FERC's inquiry into the western energy markets for 2000 and 2001. In April 2005 and June 2005, the California Parties and the City of Tacoma, respectively, filed petitions for review of the FERC's decisions approving the Agreement in Resolution with the United States Court of Appeals for the Ninth Circuit (Ninth Circuit). Based on the FERC's order approving the Agreement in Resolution and the FERC's denial of rehearing requests, the Company does not expect that this proceeding will have any material adverse effect on its financial condition, results of operations or cash flows.

Class Action Securities Litigation

On June 1, 2007, Avista Corp. entered into a settlement agreement with respect to a class action lawsuit filed against Avista Corp., Thomas M. Matthews, a former Chairman of the Board, President and Chief Executive Officer of Avista Corp., Gary G. Ely, a former Chairman of the Board, President and Chief Executive Officer of Avista Corp., and Jon E. Eliassen, a former Senior Vice President and Chief Financial Officer of Avista Corp. The settlement agreement was filed in the United States District Court for the Eastern District of Washington (the Court) on June 4, 2007.

The lawsuit commenced with the filing of several class action complaints in the Court in September through November 2002. These complaints were subsequently consolidated and ultimately dismissed by the Court in October 2005. The order to dismiss was issued without prejudice, however, which allowed the plaintiffs to file an amended complaint. The amended class action complaint was filed on November 10, 2005 and asserted claims on behalf of all persons who purchased, converted, exchanged or otherwise acquired the Company's common stock during the period between November 23, 1999 and August 13, 2002.

The settlement agreement provides for certification of the plaintiff class and a full release by the class and dismissal with prejudice of all claims against Avista Corp. in consideration of payment of $9.5 million into a settlement fund. The settlement payment and litigation defense costs will be paid by Avista Corp.'s insurance company with the exception of the Company's $1 million self-insured retention. The settlement agreement further provides that the individual defendants Matthews, Ely and Eliassen will be dismissed from the lawsuit.

The Company vigorously contested this lawsuit since it commenced on September 27, 2002. The Company denied, and continues to deny in their entirety, the allegations of wrongdoing in the lawsuit, including the allegations that Avista Corp. made any false or misleading statements with regard to the Company's business, business practices, risk management or trading activity. The Company denies that it engaged in any improper trading in the California energy market or in any other market, and it denies that the price of its stock was artificially inflated by reason of the misrepresentations and omissions alleged in the lawsuit. There have been no adverse determinations by any court against Avista Corp. or any of the defendants on the merits of the claims asserted by the plaintiffs in the lawsuit, and the Company denies that shareholders were harmed by the conduct alleged in the lawsuit. Neither the settlement agreement nor any of its terms or provisions, nor the Company's decision to settle the lawsuit, should be construed as an admission or concession of any kind of the merit or truth of any of the allegations of wrongdoing in the lawsuit, or of any fault, liability or wrongdoing whatsoever on the part of Avista Corp. The Company believes that throughout the class period alleged in the lawsuit it fully and adequately disclosed all material facts regarding the Company and made no misrepresentations of material facts regarding Avista Corp. The Company nonetheless considers it desirable to settle the lawsuit in order to avoid the cost and risks of further litigation and trial, and to dispose of burdensome and protracted litigation.

In January 2008, the Court granted final approval of the settlement agreement, and entered an order certifying the class and dismissing the claims in the lawsuit with prejudice.

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 California Independent System Operator (CalISO) and the California Power Exchange (CalPX) during the period from October 2, 2000 to June 20, 2001 (Refund Period). The findings of the FERC administrative law judge were largely adopted in March 2003 by the FERC. The refunds ordered are based on the development of a mitigated market clearing price (MMCP) methodology. If the refunds required by the formula would cause a seller to recover less than its actual costs for the Refund Period, the FERC has held that the seller would be allowed to document these costs and limit its refund liability commensurately. In September 2005, Avista Energy submitted its cost filing claim pursuant to the FERC's August 2005 order and demonstrated an overall revenue shortfall for sales into the California spot markets during the Refund Period after the MMCP methodology is applied to its transactions. That filing was accepted in orders issued by the FERC in January 2006 and November 2006. In its February 2007 status report, the CalISO stated that it intends to process Avista Energy's cost offset filing. In November 2007, the CalISO filed an updated status report at the FERC stating that it continues finalizing the financial adjustment phase, in which the CalISO is making adjustments to its refund rerun settlement data to account for fuel cost allowance offsets, cost-based offsets, and interest calculations. The CalISO states that it has finished processing activities associated with the emissions cost and fuel cost offsets.

In 2001, Pacific Gas & Electric (PG&E) and Southern California Edison (SCE) defaulted on payment obligations to the CalPX and the CalISO. As a result, the CalPX and the CalISO failed to pay various energy sellers, including Avista Energy. Both PG&E and the CalPX declared bankruptcy in 2001. In March 2002, SCE paid its defaulted obligations to the CalPX. In April 2004, PG&E paid its defaulted obligations into an escrow fund in accordance with its bankruptcy reorganization. Funds held by the CalPX and in the PG&E escrow fund are not subject to release until the FERC issues an order directing such release in the California refund proceeding. As of December 31, 2007, Avista Energy's accounts receivable outstanding related to defaulting parties in California were fully offset by reserves for uncollected amounts and funds collected from defaulting parties.

In addition, in June 2003, the FERC issued an order to review bids above $250 per MW made by participants in the short-term energy markets operated by the CalISO and the CalPX from May 1, 2000 to October 2, 2000. In May 2004, the FERC provided notice that Avista Energy was no longer subject to this investigation. In March and April 2005, the California Parties and PG&E, respectively, petitioned for review of the FERC's decision by the Ninth Circuit. In addition, many of the other orders that the FERC has issued in the California refund proceedings are now on appeal before the Ninth Circuit. Some of those issues were consolidated as a result of a case management conference conducted in September 2004. In October 2004, the Ninth Circuit ordered that briefing proceed in two rounds. The first round is limited to three issues: (1) which parties are subject to the FERC's refund jurisdiction in light of the exemption for government-owned utilities in section 201(f) of the Federal Power Act (FPA); (2) the temporal scope of refunds under section 206 of the FPA; and (3) which categories of transactions are subject to refunds. In September 2005, the Ninth Circuit held that the FERC did not have the authority to order refunds for sales made by municipal utilities in the California Refund Case. In its Order on Remand, issued in October 2007, the FERC ordered the CalISO and the CalPX to complete their refund calculations, including all entities that participated in the CalISO/CalPX markets (including those amounts that would have been paid by municipal utility entities for their sales into the CalISO and the CalPX spot markets during the refund period). The FERC then directed the CalISO to reduce refunds owed to refund recipients by the amounts attributable to municipal sales to the California markets.

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 a FPA section 309 remedy for tariff violations prior to October 2, 2000. The Ninth Circuit also granted California's petition for review challenging the FERC's exclusion of the energy exchange transactions as well as the FERC's exclusion of forward market transactions from the California refund proceedings. Petitions for rehearing were filed on November 16, 2007. It is unclear at this time what impact, if any, the Court's remand might have on Avista Energy. The second round of issues and their corresponding briefing schedules have not yet been set by the Ninth Circuit.

Any potential liabilities or refunds owed by or to Avista Energy in the California Refund Proceeding were retained by Avista Corp. and/or its subsidiaries and have not been transferred to Shell Energy and/or its affiliates.
Because the resolution of the California refund proceeding remains uncertain, legal counsel cannot express an opinion on the extent, if any, of the Company's liability. However, based on information currently known to the Company's management, the Company does not expect that the California refund proceeding will have a material adverse effect on its financial condition, results of operations or cash flows. This is primarily due to the fact that 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. During the hearing, Avista Corp. and Avista Energy vigorously opposed claims that rates for spot market sales were unjust and unreasonable and that the imposition of refunds would be appropriate. In June 2003, the FERC terminated the Pacific Northwest refund proceedings, after finding that the equities do not justify the imposition of refunds. These equitable factors included the fact that the participants in the Pacific Northwest market include not only utilities and other entities that are subject to FERC jurisdiction, but also a very substantial number of governmental entities that are not subject to FERC jurisdiction with respect to wholesale sales and thus could not be ordered by the FERC to make refunds based on existing law. Seven petitions for review were filed with the Ninth Circuit challenging the merits of the FERC's decision not to order refunds and raising procedural issues.

On August 24, 2007, the Ninth Circuit issued its opinion on the consolidated petitions for review of the Pacific Northwest refund proceeding. 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 in the Pacific Northwest and ultimately consumed in California. The Ninth Circuit expressly declined to direct the FERC to grant refunds. Requests for rehearing were filed on December 17, 2007.

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, if refunds were ordered by the FERC, could be liable to make payments, but also could assert claims for refunds against FERC-jurisdictional entities. The opportunity to make claims against non-jurisdictional entities may be limited based on existing law. 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 or could be entitled to receive. 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

In May 2002, the FERC conditionally dismissed a complaint filed in March 2002 by the Attorney General of the State of California (California AG) that alleged violations of the Federal Power Act 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 but directing sellers to re-file certain transaction summaries. It was not clear that Avista Corp. and its subsidiaries were subject to this directive but the Company took the conservative approach and re-filed certain transaction summaries in June and July of 2002. In July 2002, the California AG requested a rehearing on the FERC order, which request was denied in September 2002. Subsequently, the California AG filed a Petition for Review of the FERC's decision with the Ninth Circuit. In September 2004, the Ninth Circuit upheld the FERC's market-based rate authority, but found the requirement that all sales at market-based rates be contained in quarterly reports filed with the FERC to be integral to a market-based rate tariff. The California AG has interpreted the decision as providing authority to the FERC to order refunds in the California refund proceeding for an expanded refund period. The Court's decision leaves to the FERC the determination as to whether refunds are appropriate. In October 2004, Avista Energy joined with others in seeking rehearing of the Court's decision to remand the case back to the FERC for further proceedings. The Court denied the request without explanation on July 31, 2006. A petition for a writ of certiorari with the United States Supreme Court was denied on June 18, 2007. The proceeding is now on remand before the FERC. Based on information currently known to the Company's management, the Company does not expect that this matter will have a material adverse effect on its financial condition, results of operations or cash flows.

Wah Chang Complaint

In May 2004, Wah Chang, a division of TDY Industries, Inc. (a subsidiary of Allegheny Technologies, Inc.), filed a complaint in the United States District Court for the District of Oregon against numerous companies, including Avista Corp., Avista Energy and Avista Power. This complaint was similar to the Port of Seattle and City of Tacoma complaints (which were dismissed by the United States District Court and the Ninth Circuit as disclosed in the Company's prior Securities and Exchange Commission filings) and was seeking compensatory and treble damages for alleged violations of the Sherman Act, the Racketeer Influenced and Corrupt Organization Act, as well as violations of Oregon state law. According to the complaint, from September 1997 to September 2002, the plaintiff purchased electricity from PacifiCorp pursuant to a contract that was indexed to the spot wholesale market price of electricity. The plaintiff alleged that the defendants, acting in concert among themselves and/or with Enron Corporation and certain affiliates thereof (collectively, Enron) and others, engaged in a scheme to defraud electricity customers by transmitting false market information in interstate commerce in order to artificially increase the price of electricity provided by them, to receive payment for services not provided by them and to otherwise manipulate the market price of electricity, and by executing wash trades and other forms of market manipulation techniques and sham transactions. The plaintiff also alleged that the defendants, acting in concert among themselves and/or with Enron and others, engaged in numerous practices involving the generation, purchase, sale, exchange, scheduling and/or transmission of electricity with the purpose and effect of causing a shortage (or the appearance of a shortage) in the generation of electricity and congestion (or the appearance of congestion) in the transmission of electricity, with the ultimate purpose and effect of artificially and illegally fixing and raising the price of electricity in California and throughout the Pacific Northwest. As a result of the defendants' alleged conduct, the plaintiff allegedly suffered damages of not less than $30 million through the payment of higher electricity prices. In September 2004, this case was transferred to the United States District Court for the Southern District of California for consolidation with other pending actions. In February 2005, the Court granted the defendants' motion to dismiss the complaint because it determined that it was without jurisdiction to hear the plaintiff's complaint, based on, among other things, the exclusive jurisdiction of the FERC and the filed-rate doctrine. In March 2005, Wah Chang filed an appeal with the Ninth Circuit. On November 20, 2007, the Ninth Circuit dismissed Wah Chang's appeal and affirmed the district court's action. On December 3, 2007, Wah Chang filed a petition for rehearing with the Ninth Circuit. On January 15, 2008, the Ninth Circuit denied Wah Chang's petition for rehearing. Based on the Ninth Circuit's dismissal of this complaint and denial of the petition for rehearing, the Company believes that this complaint will not have a material adverse effect on the Company's financial condition, results of operations or cash flows.

State of Montana Proceedings

In June 2003, the Attorney General of the State of Montana (Montana AG) filed a complaint in the Montana District Court on behalf of the people of Montana and the Flathead Electric Cooperative, Inc. against numerous companies, including Avista Corp. The complaint alleges that the companies illegally manipulated western electric and natural gas markets in 2000 and 2001. This case was subsequently moved to the United States District Court for the District of Montana; however, it has since been remanded back to the

Montana District Court.

The Montana AG also petitioned the Montana Public Service Commission (MPSC) to fine public utilities $1,000 a day for each day it finds they engaged in alleged "deceptive, fraudulent, anticompetitive or abusive practices" and order refunds when consumers were forced to pay more than just and reasonable rates. In February 2004, the MPSC issued an order initiating investigation of the Montana retail electricity market for the purpose of determining whether there is evidence of unlawful manipulation of that market. The Montana AG has requested specific information from Avista Energy and Avista Corp. regarding their transactions within the state of Montana during the period from January 1, 2000 through December 31, 2001.

Because the resolution of these proceedings remains uncertain, legal counsel cannot express an opinion on the extent, if any, of the Company's liability. However, based on information currently known to the Company's management, the Company does not expect that these proceedings will have a material adverse effect on its financial condition, results of operations or cash flows.

Montana Public School Trust Fund Lawsuit
In October 2003, a lawsuit was originally filed by two residents of the state of Montana in the United States District Court for the District of Montana against private owners of hydroelectric dams in Montana, including Avista Corp. The lawsuit alleged that the hydroelectric facilities are located on state-owned riverbeds and the owners of the dams have never paid compensation to the state's public school trust fund. The lawsuit requested lease payments prospectively and also requested damages for trespassing and unjust enrichment for periods of time dating back to the construction of the respective dams. In May 2004, the Montana AG filed a complaint on behalf of the state in the District Court to join in this lawsuit to allegedly protect and preserve state lands/school trust lands from use without compensation. Through a series of legal developments, the case was subsequently moved to the Montana State Court and the original plaintiffs were removed from the case.

On August 28, 2007, the Montana State Court ruled on several pre-trial motions for summary judgment, finding that, as a matter of law, the Clark Fork River was navigable and the state of Montana owns the riverbeds, that such lands are school trust fund lands, and therefore, the statutes of limitations had not run out on the state of Montana's claims for prior damages.

On October 19, 2007, the Company reached a settlement with the state of Montana resolving this matter. Pursuant to the settlement, Avista Corp. has agreed to make lease payments in the initial amount of $4 million per year beginning February 1, 2008, for the calendar year 2007, and continuing through calendar year 2016, adjusted each year by the Consumer Price Index. On or before June 30, 2016, Avista Corp. and the state of Montana will determine whether the annual lease payments remain consistent with the principles of law as applied to the facts and negotiate an adjusted lease payment for the remaining term of Avista Corp.'s FERC license for its hydroelectric facilities on the Clark Fork River, which expires in 2046. If Avista Corp. and the state of Montana do not agree on an adjusted lease payment, the parties will engage in advisory arbitration and submit the arbitrator's recommendation to the State Board of Land Commissioners (Land Board) for approval. The settlement contains provisions that could reduce the amount of Avista Corp.'s lease payments as a result of future judicial determinations in related cases or governmental actions. Avista Corp. will not make any lease payments for periods prior to 2007.

Avista Corp. and the state of Montana have received a consent decree from the Montana State Court adopting the terms of the settlement, and the settlement was approved by the Land Board. The Company received approval from the WUTC and the IPUC to defer any lease payments as a regulatory asset. The Company believes that such costs will be recovered in future rates based on historical recovery of similar costs.

Colstrip Generating Project Complaints
In May 2003, various parties (all of which are residents or businesses of Colstrip, Montana) filed a consolidated complaint against the owners of the Colstrip Generating Project (Colstrip) in Montana District Court. Avista Corp. owns a 15 percent interest in Units 3 & 4 of Colstrip. The plaintiffs allege damages to buildings as a result of rising ground water, as well as damages from contaminated waters leaking from the lakes and ponds of Colstrip. The plaintiffs are seeking punitive damages, an order by the court to remove the lakes and ponds and the forfeiture of all profits earned from the generation of Colstrip. The owners of Colstrip have undertaken certain groundwater investigation and remediation measures to address groundwater contamination. These measures include improvements to the lakes and ponds of Colstrip.

In March 2007, a group of ranchers filed a consolidated complaint against the owners of Colstrip in Montana District Court. The plaintiffs allege damages to livestock, land and water from contaminated waters leaking from the waste water pond of Colstrip. The plaintiffs are seeking unspecified punitive damages.

The complaints were consolidated and a trial date is scheduled for June 2, 2008. The Company intends to continue to work with the other owners of Colstrip in defense of this consolidated complaint. Because the resolution of this consolidated complaint remains uncertain, legal counsel cannot express an opinion on the extent, if any, of the Company's liability. However, based on information currently known to the Company's management, the Company does not expect this consolidated complaint will have a material adverse effect on its financial condition, results of operations or cash flows.

Colstrip Royalty Claim
Western Energy Company (WECO) supplies coal to the owners of Colstrip Units 3 & 4 under a Coal Supply Agreement and a Transportation Agreement. Avista Corp. owns a 15 percent interest in Colstrip Units 3 & 4. The Minerals Management Service (MMS) of the United States Department of the Interior issued orders to WECO to pay additional royalties concerning coal delivered to Colstrip Units 3 & 4 via the conveyor belt. The owners of Colstrip Units 3 & 4 take delivery of the coal at the beginning of the conveyor belt. The orders assert that additional royalties are owed to MMS as a result of WECO not paying royalties in connection with revenue received by WECO from the owners of Colstrip Units 3 & 4 under the Transportation Agreement during the period October 1, 1991 through December 31, 2004. WECO's appeal to the MMS for the period through 2001 was substantially denied in March 2005; WECO appealed the orders pertaining to the periods up to 2001 to the Board of Land Appeals of the U.S. Department of the Interior, which appeal was denied on September 12, 2007. WECO also filed an appeal with the MMS pertaining to the period from 2002 to 2004. The entire appeal process could take several years to resolve. The owners of Colstrip Units 3 & 4 are monitoring the appeal process between WECO and MMS. WECO has indicated to the owners of Colstrip Units 3 & 4 that if WECO is unsuccessful in the appeal process, WECO will seek reimbursement of any royalty payments by passing these costs through the Coal Supply Agreement. The owners of Colstrip Units 3 & 4 advised WECO that their position would be that these claims are not allowable costs per the Coal Supply Agreement nor the Transportation Agreement in the event the owners of Colstrip Units 3 & 4 were invoiced for these claims. Presumably, royalty and tax demands for periods of time after the years in dispute and future years will be determined by the outcome of the pending proceedings. Because the resolution of this issue remains uncertain, legal counsel cannot express an opinion on the extent, if any, of the Company's liability. Based on information currently known to the Company's management, the Company does not expect that this issue will have a material adverse effect on its financial condition, results of operations or cash flows. However, the Company would most likely seek recovery, through the rate making process, of any amounts paid.

Spokane River
The Company entered into a settlement with the state of Washington's Department of Ecology (DOE) and Kaiser Aluminum & Chemical Corporation (Kaiser) relating to the remediation of a contaminated site on the Spokane River. The Company's involvement with this contaminated site relates to its previous ownership of a wastewater treatment plant through Avista Development. Kaiser paid the Company approximately 50 percent of the estimated total costs. Under the direction of the Company, work under the Cleanup Action Plan was substantially completed in 2007.

Northeast Combustion Turbine Site
In August 2005, a diesel fuel spill occurred at the Company's Northeast Combustion Turbine generating facility (Northeast CT) located in Spokane, Washington. The Northeast CT site had fuel storage facilities that were leased to Co-op Supply, Inc., an affiliate of Cenex Cooperative (Co-op). The Company immediately commenced remediation efforts, including the removal of contaminated soil and the related fuel storage facilities. The Company accrued the estimated cleanup costs during 2005, which was not material to the Company's financial condition or results of operations. Through mediation the Company recovered a substantial portion of the cleanup costs from Co-op and an engineering firm in the fourth quarter of 2006. The Company's estimate of its liability could change in future periods. Based on information currently known to the Company's management, the Company does not believe that such a change would be material to its financial condition, results of operations or cash flows.

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., as a customer 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. 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. 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 total cost of the RI/FS is estimated to be \$0.6 million and will take approximately 2 1/2 years to

complete. The actual cleanup, if any, will not occur until the RI/FS is complete. Based on the review of its records related to Harbor Oil, the Company does not believe it is a major contributor to this potential environmental contamination based on the relative volume of waste oil delivered to the Harbor Oil site. However, there is currently not enough information to allow the Company to assess the probability or amount of a liability, if any, being incurred. As such, it is not possible to make an estimate of any liability at this time.

Lake Coeur d'Alene
In July 1998, the United States District Court for the District of Idaho issued its finding that the Coeur d'Alene Tribe of Idaho (Tribe) owns, among other things, portions of the bed and banks of Lake Coeur d'Alene (Lake) lying within the current boundaries of the Coeur d'Alene Reservation. This action had been brought by the United States on behalf of the Tribe against the state of Idaho. The Company was not a party to this action. The United States District Court decision was affirmed by the Ninth Circuit. The United States Supreme Court affirmed this decision in June 2001. This ownership decision will result in, among other things, the Company being liable to the Tribe for compensation for the use of reservation lands under Section 10(e) of the Federal Power Act.

The Company's Post Falls Hydroelectric Generating Station (Post Falls), a facility constructed in 1906 with annual generation of 10 aMW, utilizes a dam on the Spokane River downstream of the Lake which controls the water level in the Lake for portions of the year (including portions of the lakebed owned by the Tribe). The Company has other hydroelectric facilities on the Spokane River downstream of Post Falls, but these facilities do not affect the water level in the Lake. The Company and the Tribe are engaged in discussions related to past and future compensation (which may include interest) for use of the portions of the bed and banks of the Lake, which are owned by the Tribe. If the parties cannot agree on the amount of compensation, the matter could result in litigation. The Company cannot predict the amount of compensation that it will ultimately pay or the terms of such payment. The Company intends to seek recovery, through the rate making process, of any amounts paid.

Spokane River Relicensing
The Company owns and operates six hydroelectric plants on the Spokane River, and five of these (Long Lake, Nine Mile, Upper Falls, Monroe Street and Post Falls, which have a total present capability of 155.7 MW) are under one FERC license 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. Since the FERC was unable to issue new license orders prior to the August 1, 2007 expiration of the current license, an annual license was issued, in effect extending the current license and its conditions until August 1, 2008. The Company has no reason to believe that Spokane River Project operations will be interrupted in any manner relative to the timing of the FERC's actions.

The Company filed a Notice of Intent to Relicense in July 2002. The formal consultation process involving planning and information gathering with stakeholder groups has been underway since that time. The Company filed its new license applications with the FERC in July 2005. The Company requested the FERC to consider a license for Post Falls, which has a present capability of 18 MW, that is separate from the other four hydroelectric plants because Post Falls presents more complex issues that may take longer to resolve than those relating to the rest of the Spokane River Project. If granted, new licenses would have a term of 30 to 50 years. In the license applications, the Company proposed a number of measures intended to address the impact of the Spokane River Project and enhance resources associated with the Spokane River.

Since the Company's July 2005 filing of applications to relicense the Spokane River Project, the FERC has continued various stages of processing the applications. In May 2006, the FERC issued a notice requesting other parties to provide terms and conditions regarding the two license applications. In response to that notice, a number of parties (including the Coeur d'Alene Tribe, the state of Idaho, Washington state agencies, and the United States Department of Interior (DOI)) filed either recommended terms and conditions, pursuant to Sections 10(a) and 10(j) of the Federal Power Act (FPA), or mandatory conditions related to the Post Falls application, pursuant to Section 4(e) of the FPA. The Company's initial estimate of the potential cost of the conditions proposed for Post Falls total between $400 million and $500 million over a 50-year period. For the rest of the Spokane River Project, which is located in Washington, the Company's initial estimate of the cost of meeting the recommended conditions, should they be included in a final license, totaled between $175 million and $225 million over a 50-year period. These cost estimates were based on the preliminary conditions and recommendations.

The Company requested a trial-type hearing in front of an Administrative Law Judge (ALJ) on facts related to the DOI's mandatory conditions for Post Falls. In January 2007, the ALJ issued his ruling regarding the Company's challenge of the facts. The Company believes that the ALJ's findings supported, in several key areas, its analysis of the facts at hand. The ALJ's factual findings also supported the DOI's analysis in certain areas as well.

The DOI issued final mandatory conditions for Post Falls on May 7, 2007, which reflected the findings of the ALJ. Most significantly, the DOI dropped an earlier proposed fishery condition. However, the DOI increased obligations that the Company could incur in other areas, such as wetlands restoration.

In July 2007, the FERC issued a Final Environmental Impact Statement (FEIS) after review and consideration of comments. This is the last administrative step for the FERC before the issuance of license orders; however, the FERC cannot proceed until several other matters are resolved, including Clean Water Act and Endangered Species Act issues as disclosed below. The Company continues to review the FEIS and related documents. While the Company believes the ultimate cost of relicensing will be less than its earlier projections as disclosed above, the Company has not developed specific new cost estimates at this point.

The relicensing process also triggers review under the Endangered Species Act. In the FEIS, the FERC analyzed potential project impacts on listed and threatened endangered species, and has determined that the proposed action and continued operation of Post Falls and the rest of the Spokane River Project is not likely to adversely affect any threatened or endangered species. The Company prepared a draft Biological Assessment in 2005. The FERC has issued a Biological Assessment and formally requested concurrence from the United States Department of Fish and Wildlife Service (USFWS). The USFWS responded by letter, concurring with regards to bald eagles, and requesting additional information regarding bull trout. The Company filed a supplemental report to address the USFWS information request. The Company has continued informal consultation with the USFWS. If the FERC initiates formal consultation with the USFWS, additional evaluation will be required by the Company.

In addition, the Company must receive Clean Water Act Certifications from the states of Idaho and Washington for the Spokane River Project. Applications for such certification were filed in July 2006 with each state. Both Idaho and Washington communicated to the Company that they were unable to complete the certifications within one year as mandated by the Clean Water Act. Subsequently, the Company withdrew these applications and re-filed for certification in June 2007. The FERC is precluded from issuing a license order until such certifications are issued, or waived, by the states. The Company cannot predict the schedule for these final phases of relicensing.

The total annual operating and capitalized costs associated with the relicensing of the Spokane River Project will become better known and estimable as the process continues. The Company intends to seek recovery, through the rate making process, of all such operating and capitalized costs.

Clark Fork Settlement Agreement

Dissolved atmospheric gas levels 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, the Company developed an abatement and mitigation strategy with the other signatories to the agreement and completed the Gas Supersaturation Control Program (GSCP). The Idaho Department of Environmental Quality and the USFWS approved the GSCP in February 2004 and the FERC issued an order approving the GSCP in January 2005.

The GSCP provides for the opening and modification of one and, potentially, both of the two existing diversion tunnels built when Cabinet Gorge was originally constructed. When river flows exceed the capacity of the powerhouse turbines, the excess flows would be diverted to the tunnels rather than released over the spillway. The Company has undertaken physical and computer modeling studies to confirm the feasibility and likely effectiveness of the tunnel solution. Analysis of the predicted total dissolved gas (TDG) performance indicates that the tunnels will not meet the performance criteria anticipated in the GSCP. In August 2007, the Gas Supersaturation Subcommittee concluded that the tunnel project does not meet the expectations of the GSCP and is not an acceptable project. As a result, the Company will continue meeting with key stakeholders to review and amend the GSCP which includes developing alternatives to the construction of the tunnels. The Company intends to seek recovery, through the rate making process, of the costs to address the dissolved atmospheric gas levels.

The USFWS has listed bull trout as threatened under the Endangered Species Act. The Clark Fork Settlement Agreement describes programs intended to restore bull trout populations in the project area. Using the concept of adaptive management and working closely with the USFWS, the Company is evaluating the feasibility of fish passage at Cabinet Gorge and Noxon Rapids. The results of these studies will help the Company and other parties determine the best use of funds toward continuing fish passage efforts or other bull trout population enhancement measures.

Air Quality

The Company must be in compliance with requirements under the Clean Air Act and Clean Air Act Amendments for its thermal generating plants. The Company continues to monitor legislative developments at both the state and national level for the potential of further restrictions on sulfur dioxide, nitrogen oxide, carbon dioxide, as well as other greenhouse gas and mercury emissions.

In particular, the EPA finalized mercury emission regulations that will affect coal-fired generation plants, including Colstrip. The new EPA regulations establish an emission trading program to take effect beginning in January 2010, with a second phase to take effect in 2018. In addition, in 2006, the Montana Department of Environmental Quality (DEQ) adopted final rules for the control of mercury emissions from coal-fired plants that are more restrictive than EPA regulations. The new rules set strict mercury emission limits by 2010, and put in place a recurring ten-year review process to ensure facilities are keeping pace with advancing technology in mercury emission control. The rules also provide for temporary alternate emission limits provided certain provisions are met, and they allocate mercury emission credits in a manner that rewards the cleanest facilities. In February 2008, the United States Court of Appeals for the District of Columbia overturned the EPA's mercury emissions regulations. However, this ruling is not expected to affect the Company's current plans to comply with the more restrictive regulations adopted by the Montana DEQ as described below.

Compliance with these new and proposed requirements and possible additional legislation or regulations will result in increases to capital expenditures and operating expenses for expanded emission controls at the Company's thermal generating facilities. The Company, along with the other owners of Colstrip, completed the first phase of testing on two mercury control technologies. Although the mercury reduction targets as mandated by the Montana DEQ have not been achieved, the owners of Colstrip are encouraged with the preliminary results and believe it should be possible to achieve the required emissions levels with further mercury control system optimization. Preliminary estimates indicate that the Company's share of installation capital costs would be $1.3 million and annual operations and maintenance costs would increase by $2.8 million (beginning in mid-2009). The Company will continue to seek recovery, through the rate making process, of the costs to comply with various air quality requirements.

Residential Exchange Program
The residential exchange program is intended to provide access to the benefits of low-cost federal hydroelectricity to residential and small-farm customers of the region's private (investor owned) and public utilities (governmental or customer owned). The Bonneville Power Administration (BPA) administers the residential exchange program under the Northwest Power Act. Previously, Avista Corp. and other private utilities in the Pacific Northwest executed settlement agreements with BPA to resolve each party's rights and obligations under the residential exchange program. These settlements covered payment of benefits for the period October 1, 2001, through September 30, 2011. The payments Avista Corp. received under the agreements with the BPA were passed through to its residential and small-farm customers via a credit to their monthly electric bills.

Several public utilities and other parties filed suit against the BPA in the Ninth Circuit, challenging the validity of the agreements between Avista Corp. and the BPA, as well as BPA's agreements with other private utilities. On May 3, 2007, the Ninth Circuit ruled that the BPA exceeded its authority when it entered into the settlement agreements with private utilities (including Avista Corp.) for the period from 2001 through 2011. The BPA concluded that the Ninth Circuit's decisions created substantial doubt about whether its certifying official could allow continuation of payments under the settlement agreements. Consequently, on May 21, 2007, the BPA notified Avista Corp. and other private utilities that it was immediately suspending payments the BPA made to them pursuant to the settlement agreements. In its May 21, 2007 notice, the BPA indicated that the suspension of payments would continue at least until any requests for rehearing were filed and the Ninth Circuit issued final decisions on those requests for rehearing. On July 18, 2007 Avista Corp. and numerous other parties, including the Public Utility Commission of Oregon and the WUTC, filed petitions for review, and review *en banc*, in the Ninth Circuit, challenging the ruling of the panel that struck down the settlement agreements. The Ninth Circuit subsequently denied these requests. Three private utilities, including Avista Corp., filed a petition for writ of certiorari with the United States Supreme Court.

With approval from the WUTC and the IPUC, Avista Corp. eliminated the credit associated with the settlement agreements with the BPA from its customers' monthly electric bills. Avista Corp. has an over-refunded balance of approximately $4.0 million ($3.3 million in Washington and $0.7 million in Idaho) because of the timing of payments received from the BPA and allocation of those funds to customers based on seasonal demand. When the existing rate credit was established it was projected that the balancing account would reach zero at the end of the contract year (October 2007). Avista Corp. is recovering the over-refund in Idaho through an approved surcharge to customers, and expects to ultimately recover the over-refund in Washington, either through a charge to customers or future payments from the BPA.

Beginning in June 2007, the region's private and public utilities worked toward an agreement that would identify an appropriate level of benefits for customers served by the private utilities, including the resolution of outstanding legal issues associated with the May 3 Ninth Circuit opinions. The BPA is working on a long-term resolution of residential exchange issues as part of its 2009 rate case. In addition to resolving residential exchange issues for the long-term, the BPA has also proposed an interim payout of $336 million to private utilities for its fiscal year 2008, to be paid out during the period April 1, 2008 to September 30, 2008. If interim contracts can be successfully executed, the portion of this payout that would benefit Avista Corp.'s customers would have no impact on Avista Corp.'s net income.

Since the residential exchange settlement payments were passed through to Avista Corp.'s customers as adjustments to electric bills, the suspension of payments from the BPA is not expected to have any effect on Avista Corp.'s net income. There is currently not enough information to allow Avista Corp. to assess the probability or amount of any potential liability that may be incurred related to any issues regarding payments made to Avista Corp. pursuant to the settlement agreements. Since 2001, Avista Corp. passed through to its customers approximately $70 million pursuant to the settlement agreements.

Other Contingencies
In the normal course of business, the Company has various other legal claims and contingent matters outstanding. The Company believes that any ultimate liability arising from these actions will not have a material adverse 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 in-depth 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 have and have not agreed to a settlement and recoveries from insurance carriers. The Company's policy is to accrue and charge to current expense identified exposures related to environmental remediation sites based on estimates of investigation, cleanup and monitoring costs to be incurred.

The Company has potential liabilities under the Federal Endangered Species Act for species of fish that have either already been added to the endangered species list, been listed as "threatened" or been petitioned for listing. Thus far, measures adopted and implemented have had minimal impact on the Company.

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 potentially adversely affect the energy production of the Company's Cabinet Gorge and Noxon Rapids hydroelectric facilities. The Company is participating in this extensive adjudication process, which is unlikely to be concluded in the foreseeable future.

As of December 31, 2007, the Company's collective bargaining agreement with the International Brotherhood of Electrical Workers represented approximately 50 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 2009. Three local agreements in Oregon, which cover approximately 50 employees, expire in April 2010.

NOTE 25: POTENTIAL HOLDING COMPANY FORMATION

At the 2006 Annual Meeting of Shareholders in May 2006, the shareholders of Avista Corp. approved a proposal to proceed with a statutory share exchange, which would change the Company's organization to a holding company structure. The holding company, currently named AVA Formation Corp. (AVA), would become the parent of Avista Corp. After the contemplated dividend to AVA of the capital stock of Avista Capital (Avista Capital Dividend) now held by Avista Corp., AVA would then also be the parent of Avista Capital. The Avista Capital Dividend would effect the structural separation of Avista Corp.'s non-utility businesses from its regulated utility business.

Avista Corp. received approval from the FERC in April 2006 (conditioned on approval by the state regulatory agencies), the IPUC in June 2006 and the WUTC in February 2007. Avista Corp. has also filed for approval from the utility regulators in Oregon and Montana and proceedings are pending in each of these jurisdictions. The statutory share exchange is subject to the receipt of the remaining regulatory approvals and the satisfaction of other conditions. If the statutory share exchange and the implementation of the holding company structure are approved by regulators on terms acceptable to the Company, it may be completed sometime in 2008.

The IPUC accepted a stipulation entered into between Avista Corp. and the IPUC Staff that sets forth a variety of conditions, which would serve to segregate the Company's utility operations from the other businesses conducted by the holding company. The stipulation would require Avista Corp. to maintain certain common equity levels as part of its capital structure. Avista Corp. committed to increase its actual utility common equity component to 35 percent by the end of 2007 and 38 percent by the end of 2008, which is consistent with provisions of the Company's Washington general rate case implemented on January 1, 2006. The calculation of the utility equity component is essentially the ratio of Avista Corp.'s total common equity to total capitalization excluding, in each case, Avista Corp.'s investment in Avista Capital. The utility equity component was approximately 45 percent as of December 31, 2007. In addition, IPUC approval would be required for any dividend from Avista Corp. to the holding company that would reduce utility common equity below 25 percent of total capitalization which, for this purpose, includes long and short-term debt, capitalized lease obligations and preferred and common equity.

The WUTC accepted a similar stipulation entered into between Avista Corp. and the WUTC staff. The stipulation requires Avista Corp. to increase its actual utility common equity component to 40 percent by June 30, 2008. In addition, WUTC approval would be required for any dividend from Avista Corp. to the holding company that would reduce utility common equity below 30 percent of total capitalization.

Pursuant to the Plan of Share Exchange, a statutory share exchange would be effected whereby each outstanding share of Avista Corp. common stock would be exchanged for one share of AVA common stock, no par value, so that holders of Avista Corp. common stock would become holders of AVA common stock and Avista Corp. would become a subsidiary of AVA. The other outstanding securities of Avista Corp. would not be affected by the statutory share exchange, with limited exceptions for stock options and other securities outstanding under equity compensation and employee benefit plans.

NOTE 26. INFORMATION SERVICES CONTRACTS

The Company has information services contracts that expire at various times through 2012. Total payments under these contracts were $15.4 million in 2007, $12.5 million in 2006 and $12.8 million in 2005. The majority of the costs are included in operation expenses in the Statements of Income. Minimum contractual obligations under the Company's information services contracts are $14.7 million in 2008, $15.1 million in 2009, $15.4 million in 2010, $14.5 million in 2011 and $14.5 million in 2012. 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.

NOTE 27. PRIOR PERIOD ADJUSTMENT

During preparation of the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2007, the Company determined that SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions" was inadvertently not followed in connection with a plan under which benefits are provided to the beneficiaries of former and current executive officers of the Company in case of death. The Company had not previously recognized the actuarial liability or costs relating to this plan in its financial statements since the plan's inception in 1989.

The prior period adjustments decreased retained earnings by $2.5 million.

NOTE 28. SUPPLEMENTAL CASH FLOW INFORMATION

	2007	2006
Cash paid for interest	$78,704,863	$94,827,987
Cash paid for income taxes	$28,946,776	$63,361,034
Other Cash Flows from Operating Activities:		
Power and natural gas deferrals	$(3,898,852)	$(6,497,199)
Change in special deposits	$(1,625,942)	$1,366,143
Change in other current assets	$(140,981)	$(1,405,850)
Non-cash stock compensation	$2,511,576	$3,744,610
ESOP dividends	$1,045	$415,596
Gain on sale of assets	$-	$(99,559)
Regulatory disallowance of debt repurchase costs	$3,849,725	$-

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

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

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

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

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

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	(63,702)	(19,625,803)		1,407,305
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	80,309			
3	Preceding Quarter/Year to Date Changes in Fair Value	(16,607)	3,644,702		(38,746)
4	Total (lines 2 and 3)	63,702	3,644,702		(38,746)
5	Balance of Account 219 at End of Preceding Quarter/Year		(15,981,101)		1,368,559
6	Balance of Account 219 at Beginning of Current Year		(15,981,101)		1,368,559
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				(2,379,000)
8	Current Quarter/Year to Date Changes in Fair Value		3,199,837		1,010,441
9	Total (lines 7 and 8)		3,199,837		(1,368,559)
10	Balance of Account 219 at End of Current Quarter/Year		(12,781,264)		

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges Energy Commodity Derivatives (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1	(6,585,553)	1,568,605	(23,299,148)		
2	2,429,700	(546,000)	1,964,009		
3	809,492	(1,029,287)	3,369,554		
4	3,239,192	(1,575,287)	5,333,563	73,132,859	78,466,422
5	(3,346,361)	(6,682)	(17,965,585)		
6	(3,346,361)	(6,682)	(17,965,585)		
7		609,000	(1,770,000)		
8	(3,479,861)	(602,318)	128,099		
9	(3,479,861)	6,682	(1,641,901)	38,475,085	36,833,184
10	(6,826,222)		(19,607,486)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

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

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

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	3,104,139,720	2,416,047,770
4	Property Under Capital Leases	5,525,291	
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	3,109,665,011	2,416,047,770
9	Leased to Others		
10	Held for Future Use	39,828	
11	Construction Work in Progress	75,679,838	58,833,729
12	Acquisition Adjustments	22,211,433	
13	Total Utility Plant (8 thru 12)	3,207,596,110	2,474,881,499
14	Accum Prov for Depr, Amort, & Depl	1,090,037,407	822,605,052
15	Net Utility Plant (13 less 14)	2,117,558,703	1,652,276,447
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	1,057,750,680	816,649,875
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	14,017,595	5,955,177
22	Total In Service (18 thru 21)	1,071,768,275	822,605,052
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj	18,269,132	
33	Total Accum Prov (equals 14) (22,26,30,31,32)	1,090,037,407	822,605,052

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
584,809,571				103,282,379	3
1,619,845				3,905,446	4
					5
					6
					7
586,429,416				107,187,825	8
					9
39,828					10
10,811,515				6,034,594	11
22,211,433					12
619,492,192				113,222,419	13
237,135,611				30,296,744	14
382,356,581				82,925,675	15
					16
					17
218,127,944				22,972,861	18
					19
					20
738,535				7,323,883	21
218,866,479				30,296,744	22
					23
					24
					25
					26
					27
					28
					29
					30
					31
18,269,132					32
237,135,611				30,296,744	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

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

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents	15,259,132	
4	(303) Miscellaneous Intangible Plant	4,420,269	1,139,690
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	19,679,401	1,139,690
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	2,238,211	
9	(311) Structures and Improvements	124,511,943	74,542
10	(312) Boiler Plant Equipment	162,048,075	1,794,547
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	47,085,025	2,973,628
13	(315) Accessory Electric Equipment	26,261,732	75,900
14	(316) Misc. Power Plant Equipment	15,231,320	48,358
15	(317) Asset Retirement Costs for Steam Production	1,248,795	-663,519
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	378,625,101	4,303,456
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	55,508,864	492,093
28	(331) Structures and Improvements	38,023,251	1,397,109
29	(332) Reservoirs, Dams, and Waterways	107,968,070	4,218,685
30	(333) Water Wheels, Turbines, and Generators	101,869,797	13,852,548
31	(334) Accessory Electric Equipment	28,737,509	421,331
32	(335) Misc. Power PLant Equipment	6,373,927	59,871
33	(336) Roads, Railroads, and Bridges	1,999,562	
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	340,480,980	20,441,637
36	D. Other Production Plant		
37	(340) Land and Land Rights	903,118	
38	(341) Structures and Improvements	15,463,212	44,210
39	(342) Fuel Holders, Products, and Accessories	21,064,431	
40	(343) Prime Movers	21,876,780	
41	(344) Generators	196,808,535	80,939
42	(345) Accessory Electric Equipment	14,962,362	154,265
43	(346) Misc. Power Plant Equipment	1,257,948	83,218
44	(347) Asset Retirement Costs for Other Production	351,682	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	272,688,068	362,632
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	991,794,149	25,107,725

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

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

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

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

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

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
			15,259,132		3
1,955,108			3,604,851		4
1,955,108			18,863,983		5
					6
					7
5,304			2,232,907		8
16,833			124,569,652		9
2,211,303			161,631,319		10
					11
1,979,267			48,079,386		12
4,277			26,333,355		13
4,346			15,275,332		14
			585,276		15
4,221,330			378,707,227		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			56,000,957		27
29,280			39,391,080		28
30,163			112,156,592		29
1,174,503			114,547,842		30
210,053			28,948,787		31
222,726			6,211,072		32
			1,999,562		33
					34
1,666,725			359,255,892		35
					36
			903,118		37
			15,507,422		38
			21,064,431		39
			21,876,780		40
5,784			196,883,690		41
10,736			15,105,891		42
			1,341,166		43
			351,682		44
16,520			273,034,180		45
5,904,575			1,010,997,299		46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	12,994,934	752,949
49	(352) Structures and Improvements	13,788,157	1,443,114
50	(353) Station Equipment	160,310,803	9,374,441
51	(354) Towers and Fixtures	17,069,239	10,715
52	(355) Poles and Fixtures	101,662,583	24,727,793
53	(356) Overhead Conductors and Devices	74,292,127	26,408,837
54	(357) Underground Conduit	561,148	
55	(358) Underground Conductors and Devices	1,317,910	
56	(359) Roads and Trails	1,826,844	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	383,823,745	62,717,849
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	3,733,825	217,518
61	(361) Structures and Improvements	10,245,797	633,466
62	(362) Station Equipment	79,144,040	2,827,566
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	175,437,966	10,352,745
65	(365) Overhead Conductors and Devices	115,667,943	5,974,597
66	(366) Underground Conduit	61,887,346	4,024,066
67	(367) Underground Conductors and Devices	98,271,664	9,114,994
68	(368) Line Transformers	139,461,820	12,849,153
69	(369) Services	99,791,632	5,524,502
70	(370) Meters	23,722,909	2,046,755
71	(371) Installations on Customer Premises		
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	24,599,591	1,803,215
74	(374) Asset Retirement Costs for Distribution Plant	129,707	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	832,094,240	55,368,577
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	124,681	
87	(390) Structures and Improvements	2,042,518	108,811
88	(391) Office Furniture and Equipment	136,601	377,275
89	(392) Transportation Equipment	8,275,752	848,154
90	(393) Stores Equipment	120,561	180,227
91	(394) Tools, Shop and Garage Equipment	2,988,365	343,127
92	(395) Laboratory Equipment	3,039,673	35,970
93	(396) Power Operated Equipment	19,674,347	1,055,755
94	(397) Communication Equipment	28,330,864	3,979,063
95	(398) Miscellaneous Equipment	3,973	
96	SUBTOTAL (Enter Total of lines 86 thru 95)	64,737,335	6,928,382
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant		
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	64,737,335	6,928,382
100	TOTAL (Accounts 101 and 106)	2,292,128,870	151,262,223
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	2,292,128,870	151,262,223

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
			13,747,883		48
7,317			15,223,954		49
2,454,473			167,230,771		50
			17,079,954		51
143,462			126,246,914		52
103,911			100,597,053		53
			561,148		54
			1,317,910		55
			1,826,844		56
					57
2,709,163			443,832,431		58
					59
3,682			3,947,661		60
21,253			10,858,010		61
568,909			81,402,697		62
					63
245,704			185,545,007		64
152,704			121,489,836		65
55,162			65,856,250		66
550,022			106,836,636		67
1,249,685			151,061,288		68
130,868			105,185,266		69
2,421,734			23,347,930		70
					71
					72
139,815			26,262,991		73
			129,707		74
5,539,538			881,923,279		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			124,681		86
			2,151,329		87
			513,876		88
533,953			8,589,953		89
			300,788		90
37,932			3,293,560		91
7,081			3,068,562		92
673,671			20,056,431		93
70,983			32,238,944		94
85			3,888		95
1,323,705			70,342,012		96
					97
					98
1,323,705			70,342,012		99
17,432,089			2,425,959,004		100
					101
					102
					103
17,432,089			2,425,959,004		104

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	State of Washington	
2		
3	Electric Revenue blanket	811,491
4	Wood Pole Management	152,775
5	Metro-Post St. Reconductor Phase 1	156,125
6	Terre View 115-sub construct	104,569
7	Critchfield 115 sub-construct	1,439,700
8	NE sub-Increase capacity	281,681
9	Downtown West sub-property	774,957
10	Indian Trail 115-13kv sub-construct new sub	537,718
11	Rockford 24kv sub-convert to 13kv sub	103,591
12	Post St East NW Upgrade Feeders	1,847,977
13	Hydro Minor Blanket	156,160
14	Transportation Equipment	685,685
15	Productivity Initiative	220,680
16	WSDOT Highway Franchise Consolidation	229,390
17	Minor Projects (43) Under $100,000	550,541
18		
19	State of Idaho	
20		
21	Electric Revenue Blanket	155,917
22	Appleway -Purchase Property	180,067
23	Tribal Permits and Settlements	132,944
24	DREEP: Dist Reliability & Energy Efficiency Project	190,292
25	Transportation Equipment	455,515
26	Productivity Initiative	129,850
27	Minor Projects (31) Under $100,000	133,706
28		
29	Common-WA&ID	
30		
31	Benewah-Shawnee 230kv const	212,287
32	System 115kv Air Switch Upgrade	115,097
33	Beacon St Yd-Oil Containment	202,232
34	Critchfield 115 sub-Construct	322,951
35	West Plains Transmission Reinforce	1,533,941
36	Lolo 230-rebuild 230kv yard	135,256
37	Indian Trail 115-13kv sub-construct new sub	504,509
38	Latah jct 115sub-add 115 PCBs	122,399
39	C&W Kendall Project	1,832,205
40	Back up Control Center -Construct	295,025
41	Cabinet Gorge Capital Projects	226,949
42	Kettle Falls Capital Projects	196,272
43	TOTAL	58,833,729

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	Nine Mile Capital Projects	104,360
2	Noxon Capital Projects	8,504,517
3	Post Falls Capital Projects	145,090
4	Upper Falls Capital Projects	314,123
5	Northeast Combustion Turbine Capital Projects	128,572
6	Control Network	290,395
7	Cabinet Gorge Bypass Tunnel Project	4,368,876
8	CS2 Capital Projects	422,631
9	Noxon Rapids Unit 1 Turbine	4,043,707
10	Noxon Rapids Unit 2 Turbine	104,271
11	Clark Fork Implement PME Agreement	1,989,707
12	Hydro Relicensing	20,549,666
13	Transportation Equipment	757,111
14	Security Initiative	110,372
15	Back up Control Center-Communication	865,284
16	Minor Projects (108) Under $ 100,000	1,004,593
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
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32		
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34		
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36		
37		
38		
39		
40		
41		
42		
43	TOTAL	58,833,729

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

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

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

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	771,231,596	771,231,596		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	60,352,415	60,352,415		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	1,088,550	1,088,550		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	-353,988	-353,988		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	61,086,977	61,086,977		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	15,467,996	15,467,996		
13	Cost of Removal	1,844,942	1,844,942		
14	Salvage (Credit)	2,523,639	2,523,639		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	14,789,299	14,789,299		
16	Other Debit or Cr. Items (Describe, details in footnote):	-879,399	-879,399		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	816,649,875	816,649,875		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	230,332,678	230,332,678		
21	Nuclear Production				
22	Hydraulic Production-Conventional	83,857,166	83,857,166		
23	Hydraulic Production-Pumped Storage				
24	Other Production	46,617,998	46,617,998		
25	Transmission	144,269,157	144,269,157		
26	Distribution	268,572,075	268,572,075		
27	Regional Transmission and Market Operation				
28	General	43,000,801	43,000,801		

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

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

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

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
29	TOTAL (Enter Total of lines 20 thru 28)	816,649,875	816,649,875		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

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

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1				
2	Avista Capital - Common Stock	1997		184,251,609
3	Avista Capital - Equity in Earnings			61,577,075
4	OCI Investment in Subs			1,361,877
5	Avista Capital - Other Changes in Net Investment			
6	Avista Capital - Other Changes in Net Investment			
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42	Total Cost of Account 123.1 $ 0		TOTAL	247,190,561

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

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

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
		184,251,609		2
-4,360,980	-161,000,000	-103,783,905		3
	-1,361,887			4
	-11,378,300	-11,378,300		5
	2,281,868	2,281,868		6
				7
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-4,360,980	-171,458,319	71,371,272		42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	2,121,931	2,213,923	(1)
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	8,606,317	10,710,048	(1)
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	1,766,365	1,892,177	(1)
8	Transmission Plant (Estimated)	21,529		(1)
9	Distribution Plant (Estimated)	233,483	192,257	(1)
10	Regional Transmission and Market Operation Plant (Estimated)			(1),(2)
11	Assigned to - Other (provide details in footnote)	3,391,376	4,570,824	(1),(2)
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	14,019,070	17,365,306	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)			
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	16,141,001	19,579,229	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

Transmission Service and Generation Interconnection Study Costs

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

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	Centennial Power	83	186200	83	235400
3	Great Northern Power Development	1,919	186200		235400
4					
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7					
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21	**Generation Studies**				
22	RES America Developments, Inc.	3,641	186200	3,425	235400
23	PPL Montana, LLC	2,635	186200		235400
24	UPC Wind Management. LLC	7,324	186200		235400
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $50,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	FAS 106 - Post Retirement Benefits (182300)	2,836,512		107 / 926	472,752	2,363,760
2	Guaranteed Residual Value Airplane (182301)		1,826,000			1,826,000
3	FAS 158 - Post Retirement Liability (182305)	54,192,195		Various	3,186,072	51,006,123
4	FAS 109 - Utility Plant (182310)	97,259,975	4,801,483			102,061,458
5	FAS 109 - DSIT Non-Plant (182315)		3,050,796			3,050,796
6	FAS 109 - DFIT State Tax Credits (182316)		3,972,764			3,972,764
7	FAS 109 - WNP3 (182320)	8,929,265		283180	325,496	8,603,769
8	Decoupling (182328 & 182329)		225,167			225,167
9	Automated Meter Reading (182330)	16,073,389	7,314,365			23,387,754
10	RTO Deposit - ID (182340)	354,029		560350	70,806	283,223
11	BPA Residential Exchange (182345)	2,332,367	1,504,629			3,836,996
12	BPA Residential Exchange - Interest (182345)	45,909	115,953			161,862
13	ERM Approved for Reg Recovery (182350)	70,227,235			28,268,387	41,958,848
14	New Generation Install (182370)	184,236		407370	184,236	
15	Wartsilla Units (182372)	3,496,997		407380	153,132	3,343,865
16	Mark-To-Market ST (182374)	62,650,144		175 / 244	55,478,724	7,171,420
17	FAS 143 - ARO (182376)	3,291,994		108 / 230	206,871	3,085,123
18	DSM Lost Margin (182380)	(1,472,856)	1,472,856			
19	Workers Compensation (182383)	2,424,563	426,461			2,851,024
20	CS2 Levelized Return (182384)	990,483	277,292			1,267,775
21	Idaho PCA Deferral.1 (182385)		7,516,287			7,516,287
22	Idaho PCA Deferral.2 (182386)		13,646,762			13,646,762
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44	TOTAL	323,816,437	46,150,815		88,346,476	281,620,776

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Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $50,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1						
2	Colstrip Common Fac.	1,110,999		406		1,110,999
3	Regulatory Asset-Decoupling def		594,442			594,442
4	WA Deferred Power Costs	-68,246	16,633,141			16,564,895
5	WA ERM YTD Company Band	2,601,664	5,880,977			8,482,641
6	WA ERM YTD Contra Account	-2,601,664			5,880,977	-8,482,641
7	Regulatory Asset ROT Deposit	711,960			158,213	553,747
8	Regulatory Asset-Mt lease pymt		1,366,800			1,366,800
9	Regulatory Asset-Mt lease pymt		2,633,200			2,633,200
10	Colstrip Common Fac.	2,355,642		406		2,355,642
11						
12	ID Deferred Power	96,422,897		VAR	96,422,897	
13	ID Accumulated Surcharge Am	-87,065,618	87,065,618	557		
14						
15	Payroll Accrual	899,708		VAR	885,686	14,022
16	Payroll Loading Clearing					
17	Plant Allocation of clrg jrls	-2,025,687	3,063,852			1,038,165
18						
19	Misc Error Suspense	-180,812	179,774	VAR		-1,038
20						
21						
22	Misc susp acct-non w/o		200,000			200,000
23	Unamortized A/R sale	14,187			6,084	8,103
24						
25	Intangible Pension Asset					
26						
27	Nez Perce Settlement	192,021		557	5,212	186,809
28	Misc Deferred Debit Centralia	623,503	33,326			656,829
29	Centralia Mine Env Balance					
30						
31						
32	ID Panhandle Forest Use Permit	182,611	24,813			207,424
33	Metro-Sunset 115KV TE	312,998	38,508			351,506
34	Incremental trans costs	383,236			383,236	
35	UPRR Permit Conv	333,108	477			333,585
36	Insurance Recvy CDA Lake	145,090	16,901			161,991
37	Corp reorg stk iss. costs	118,086		VAR		118,086
38						
39						
40						
41	Nez Perce Permit Conversion	562,448			563,412	-964
42						
43						
44	Misc Work Orders <$50,000	38,956	88,890			127,846
45	Subsidiary Billings	3,724,886		VAR	1,599,178	2,125,708
46	"Null" Projects directly to 186	-378,778	383,236			4,458
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	31,297,127				40,642,265

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $50,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Conservation					
2	Regulatory Assets Consv	3,844,350			1,280,293	2,564,057
3	Oregon Gas Comm Consvt	34,384	5,676			40,060
4						
5	Oregon Common Gas Eff	412,435	2,343			414,778
6	WPNG HE Wtr Htrs-Oregon	572,229			311,704	260,525
7	WPNG HE Furnaces	3,836,397			1,714,517	2,121,880
8						
9	WPNG OR Res Low 1	359,746		908	16,768	342,978
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32	Energy Star Homes	136,212	139,447			275,659
33	Energy Star Manufactored Homes	7,062	9,163			16,225
34	HE Washing Machines	55,312	40,389			95,701
35	Regulatory Assets Consv	455,839			101,144	354,695
36	Regulatory Assets Consv	1,120,436			336,413	784,023
37	Conservation Rate Credit	286,095			286,095	
38	Conservation Rate Credit CRC	122,612			122,612	
39	Regulatory Assets Conservation		154,919			154,919
40						
41	Dry Creek Transport		364,432			364,432
42	Glendale Cust Premises Equip		183,654			183,654
43	Lake CDA Issues	1,626,077	324,547			1,950,624
44	Shareholder Lawsuit 2002	14,746			8,946	5,800
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	31,297,127				40,642,265

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2		13,452,219	13,791,783
3			
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	13,452,219	13,791,783
9	Gas		
10		1,953,690	3,123,264
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15	1,953,690	3,123,264
17	Other	40,196,406	73,908,056
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	55,602,315	90,823,103

Notes

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Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

CAPITAL STOCKS (Account 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Account 201 - Common Stock Issued			
2	No Par Value	200,000,000		
3	Restricted shares			
4	TOTAL_COM	200,000,000		
5				
6				
7	Account 204 - Preferred Stock Issued	10,000,000		
8				
9				
10	Cumulative			
11				
12				
13	TOTAL_PRE	10,000,000		
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Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
52,932,368	727,945,794					2
				28,137	720,307	3
52,932,368	727,945,794			28,137	720,307	4
						5
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CAPITAL STOCK EXPENSE (Account 214)

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

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Stock - Public Issue	3,294,916
2		
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22	TOTAL	3,294,916

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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LONG-TERM DEBT (Account 221, 222, 223 and 224)

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Acct. 221 - Bonds:		
2	Notes Payable - Banks (local) $320,000,000		2,406,216
3	Secured Medium Term Notes A	250,000,000	1,136,221
4	Discount		50,200
5	Secured Medium Term Notes B	161,000,000	788,947
6	Secured Medium Term Notes C	109,000,000	1,172,129
7	FMB's 6.125%	45,000,000	825,301
8	Discount		204,750
9	FMB's 5.45%	90,000,000	1,054,153
10	Discount		239,400
11	FMB's 6.25%	150,000,000	1,812,935
12	(Premium)		-266,500
13	Discount		634,000
14	FMB's 5.70%	150,000,000	4,702,304
15	Discount		222,000
16			
17	Pollution Control Revenue Bonds		
18	6% Series due 2023	4,100,000	115,355
19	Colstrip 1999A due 2032	66,700,000	2,700,582
20	Discount		20,500
21	Colstrip 1999B due 2034	17,000,000	954,386
22			
23	Acct. 222		
24	Acct. 223 Advances from associated companies	1,200,000	
25	LTD - AVA Trust III	61,856,000	1,658,634
26	LTD - AVA Trust II	51,547,000	3,633,783
27			
28	Acct. 224 Other		
29	Series K	35,000,000	2,089,391
30	Senior Notes	400,000,000	9,128,000
31	Discount		2,716,000
32	MTN's $1,000,000,000	683,000,000	2,700,797
33	TOTAL	2,275,403,000	40,699,484

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
12-17-2004	3-15-2011	12-13-2004	3-15-2011		308,938	2
Var.	Var.	Var.	Var.	68,000,000	4,897,600	3
						4
6-9-1995	7-1-2010	6-9-1995	7-1-2010	5,000,000	345,000	5
Var.	Var.	Var.	Var.	75,000,000	5,537,921	6
9-8-2003	9-1-2013	9-8-2003	9-1-2013	45,000,000	2,756,250	7
						8
11-18-2004	12-1-2019	11-18-2004	12-1-2019	90,000,000	4,905,000	9
						10
11-17-2005	12-1-2035	11-17-2005	12-1-2035	154,137,175	9,633,573	11
						12
						13
12-15-2006	7-1-2037	12-15-2006	7-1-2037	146,796,000	8,526,250	14
						15
						16
						17
12-18-1984	12-1-2023	12-18-1984	12-1-2032	4,100,000	246,000	18
9-1-1999	10-1-2032	9-1-1999	10-1-2032	66,700,000	3,335,000	19
						20
9-1-1999	3-1-2034	9-1-1999	3-1-2034	17,000,000	871,250	21
						22
						23
				1,200,000		24
4-5-2004	4-1-2034	4-30-2004	3-31-2034	61,856,000	4,020,640	25
6-3-1997	6-1-2037	6-30-1997	5-31-2037	51,547,000	3,277,565	26
						27
						28
9-15-1992	9-15-2007		9-15-2007		1,368,281	29
4-3-2001	6-1-2008	5-1-2001	6-1-2008	273,010,231	26,603,850	30
						31
1-22-1992	1-22-2007	2-1-1992	2-1-2007		411,170	32
				1,059,346,406	77,044,288	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

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

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

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	38,475,085
2		
3		
4	Taxable Income Not Reported on Books	
5		6,039,568
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		100,530,141
11	Federal Income Tax	22,193,342
12	Deferred Income Tax	3,594,288
13	Investment Tax Credit & State Income Tax	470,903
14	Income Recorded on Books Not Included in Return	
15		18,270,223
16	Equity in Sub Earnings (Income) / Loss	4,595,749
17	Corporate Overhead Unallocated Subs	1,155,955
18		
19	Deductions on Return Not Charged Against Book Income	
20		-119,263,165
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	76,062,090
28	Show Computation of Tax:	
29		
30	Federal Tax Net Income	76,062,090
31	State Tax @ 2%, Less Idaho ITC	-1,387,627
32	Federal Tax Net Income, Less State Tax	74,674,463
33		
34	Federal Tax @ 35% (74,674,463 * 35%)	26,136,062
35		
36		
37		
38	Prior Years Tax Return, Revenue Agent Report & Misc True-ups	1,823,523
39		
40	Kettle Falls & Cabinet Gorge Tax Credits	-2,689,709
41	Total Federal Tax Expense (agrees to line 11)	25,269,876
42		
43		
44		

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Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	FEDERAL:					
2	Income Tax	-30,476,283				30,476,283
3	Income Tax	2,734,453				-2,734,453
4	Income Tax	4,081,943		498,523		-27,741,830
5	Income Tax (Current)			23,057,197	21,521,809	
6	Retained Earnings	-1,463,362				1,463,362
7	Retained Earnings	-386,815				386,815
8	Prior Retained Earnings	-1,618,425		-1,544,919		-1,850,177
9	Current Retained Earnings			-2,127,838		
10	Total Federal	-27,128,489		19,882,963	21,521,809	
11						
12	STATE OF WASHINGTON:					
13	Property Tax (2005)	58,913		-58,913		
14	Property Tax (2006)	10,152,000		-1,823,436	8,329,120	
15	Property Tax (2007)			10,692,000		
16	Excise Tax (2005)	189,884		-98,432		
17	Excise Tax (2006)	1,856,345		108,563	1,965,365	-7
18	Excise Tax (2007)			22,075,121	19,460,329	
19	Natural Gas Use Tax	20,706		76,438	62,437	
20	Municipal Occupation Tax	2,645,486		20,424,230	20,374,194	
21	Sales & Use Tax (2005)	-141,202		83,793		
22	Sales & Use Tax (2006)	86,301			36,835	
23	Sales & Use Tax (2007)			1,193,636	1,133,447	
24	Motor Vehicle Tax (2007)			7,723	7,723	
25	Total Washington	14,868,433		52,680,723	51,369,450	-7
26						
27	STATE OF IDAHO:					
28	Income Tax (2005)	345,334				-345,334
29	Income Tax (2006)	-145,347		348,075	60,236	345,334
30	Income Tax (2007)			409,879	590,000	
31	Property Tax (2005)	9,691		-9,691		
32	Property Tax (2006)	1,677,111		-1,466	1,675,645	
33	Property Tax (2007)			3,286,941	1,165,864	
34	Motor Vehicle Tax (2007)			13,023	13,023	
35	Sales & Use Tax (2005)	423				13
36	Sales & Use Tax (2006)	17,968			17,968	
37	Sales & Use Tax (2007)			294,872	289,687	-12
38	Irrigation Credits (2006)					
39	KWH Tax (2006)	24,663		1,660	26,331	8
40	KWH Tax (2007)			356,210	321,852	-1
41	TOTAL	-4,887,161		95,530,026	95,360,673	-1

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
						2
						3
-23,161,363		299,758			198,765	4
1,535,388		15,615,969			7,441,228	5
						6
						7
-5,013,521					-1,544,919	8
-2,127,838					-2,127,838	9
-28,767,334		15,915,727			3,967,236	10
						11
						12
		-10,256			-48,657	13
-556		-1,346,320			-477,116	14
10,692,000		8,322,669			2,369,331	15
91,452		-138,787			40,355	16
-464		65,399			43,164	17
2,614,792		13,919,664			8,155,457	18
34,707					76,438	19
2,695,522		12,694,551			7,729,679	20
-57,409					83,793	21
49,466						22
60,189					1,193,636	23
					7,723	24
16,179,699		33,506,920			19,173,803	25
						26
						27
						28
487,826		-90,234			438,309	29
-180,121		295,742			114,137	30
		-9,580			-111	31
		15,595			-17,061	32
2,121,077		2,677,911			609,030	33
					13,023	34
436						35
						36
5,173					294,872	37
		2,683			-2,683	38
		1,660				39
34,357		356,210				40
-4,717,808		62,711,090			32,818,936	41

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	Franchise Tax (2005)	1		-1		
2	Franchise Tax (2006)	1,564,867			1,567,214	1
3	Franchise Tax (2007)			3,948,323	2,328,531	
4	Total Idaho	3,494,711		8,647,825	8,056,351	9
5						
6	STATE OF MONTANA:					
7	Income Tax (2005)	466,950		24,145	-50,548	-541,643
8	Income Tax - (2006)	-58,306		32,855		541,643
9	Income Tax - (2007)			450,279	460,000	
10	Property Tax (2005)	31,447		-31,447		
11	Property Tax (2006)	2,977,181			2,971,509	
12	Property Tax (2007)			6,177,420	3,093,315	
13	Colstrip Generation Tax			3,692	3,692	
14	KWH Tax (2004)	1				-1
15	KWH Tax (2005)	1,276				-1,276
16	KWH Tax (2006)	261,908			261,908	
17	KWH Tax (2007)			1,117,650	877,365	
18	Motor Vehicle Tax (2007)			3,691	3,691	
19	Consumer Council Tax	431		11,105	8,440	1,769
20	Public Commission Tax	503		21	21	-495
21	Total Montana	3,681,391		7,789,411	7,629,393	-3
22						
23	STATE OF OREGON:					
24	Income Tax (2005)	264,467				-264,467
25	Income Tax (2006)	37,202		-35,582		264,467
26	Income Tax (2007)			-88,274	440,000	
27	Property Tax (2005)	-473,640		762,321		
28	Property Tax (2006)	-208,947		79,500	156,343	
29	Property Tax (2007)			813,400	1,572,558	1
30	Motor Vehicle Tax (2007)			3,680	3,680	
31	BETC Credit (2000)	-431,020		11,471		31,896
32	BETC Credit (2001)	-34,244		73,379		124,805
33	BETC Credit (2002)	-55,790		3,580		6,092
34	BETC Credit (2003)	24,865				427
35	BETC Credit (2004)	26,274				10,812
36	BETC Credit (2005)	32,145		81,145		-196,186
37	BETC Credit (2006)	-104,808		-125,454		22,154
38	BETC Credit (2007)			17,786		
39	Franchise Tax (2004)	-62,168				
40	Franchise Tax (2005)	60,185				
41	TOTAL	-4,887,161		95,530,026	95,360,673	-1

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
					-1	1
-2,346						2
1,619,792		2,426,583			1,521,740	3
4,086,194		5,676,570			2,971,255	4
						5
						6
		24,145				7
516,192		-230,144			262,999	8
-9,721		450,279				9
		-31,447				10
5,672						11
3,084,105		6,177,420				12
		3,692				13
						14
						15
						16
240,285		1,117,650				17
		3,691				18
4,865		11,105				19
8		21				20
3,841,406		7,526,412			262,999	21
						22
						23
						24
266,087		-48,813			13,231	25
-528,274		-22,069			-66,205	26
288,681					762,321	27
-285,790		79,500				28
-759,157		76,843			736,557	29
					3,680	30
-387,653					11,471	31
163,940					73,379	32
-46,118					3,580	33
25,292						34
37,086						35
-82,896					81,145	36
-208,108					-125,454	37
17,786					17,786	38
-62,168						39
60,185						40
-4,717,808		62,711,090			32,818,936	41

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
1	Franchise Tax (2006)	1,138,514			1,101,020	
2	Franchise Tax (2007)			4,905,418	3,491,677	
3	Total Oregon	213,035		6,502,370	6,765,278	1
4						
5	STATE OF CALIFORNIA:					
6	Income Tax (2005)	-12,000		1,600		
7	Income Tax (2006)	-3,200		2,400		
8	Income Tax (2007)			3,200	3,200	
9	Total California	-15,200		7,200	3,200	
10						
11	MISCELLANEOUS STATES:					
12	Income Tax (2006)			1,100	1,100	
13	Income Tax (2007)					
14	Total Misc States			1,100	1,100	
15						
16	COUNTY & MUNICIPAL					
17	WA Renewable Energy	-1,044			-1,044	
18	Misc.	2		18,434	15,136	-1
19	Total County	-1,042		18,434	14,092	-1
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	-4,887,161		95,530,026	95,360,673	-1

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
37,494						1
1,413,741					4,905,418	2
-49,872		85,461			6,416,909	3
						4
						5
-10,400					1,600	6
-800					2,400	7
					3,200	8
-11,200					7,200	9
						10
						11
					1,100	12
						13
					1,100	14
						15
						16
						17
3,299					18,434	18
3,299					18,434	19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
-4,717,808		62,711,090			32,818,936	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%						
6							
7							
8	TOTAL						
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Gas Propertry (100%	472,344			411400	49,308	
11							
12	TOTAL PROPERTY	472,344				49,308	
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
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47							
48							

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ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
			3
			4
			5
			6
			7
			8
			9
423,036			10
			11
423,036			12
			13
			14
			15
			16
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			18
			19
			20
			21
			22
			23
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			46
			47
			48

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OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $10,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	CCS Install (253000)	17,092	142 / 419	16,929		163
2	Pacificorp Capacitor (253080)	23,430	142 / 456	9,372		14,058
3	BPA C&RD REceipts (253100)	108,870		108,870		
4	Centralia Environmental (253110)	935,764			29,496	965,260
5	Rathdrum Refund (253120)	442,509	550000	33,823		408,686
6	NE Tank Spil (253130)	210,625	186200	75,085		135,540
7	Bills Pole Rentals (253140)				202,867	202,867
8						
9						
10	Sale/Leaseback on Bldg (253850)	1,307,280	931000	261,456		1,045,824
11	Clark Fork Relicensing (253890)	-681,218	186/419/537	268,099		-949,317
12	Defer Comp Retired Execs (253900)	324,007	431 / 232	87,615		236,392
13	Defer Comp Active Execs (253910)	12,564,773	Various	450,117		12,114,656
14	Executive Incent Plan (253920)	140,000				140,000
15	Unbilled Revenue (253990)	2,223,389			1,534,814	3,758,203
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
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43						
44						
45						
46						
47	TOTAL	17,616,521		1,311,366	1,767,177	18,072,332

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ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	232,595,098	11,008,524	
3	Gas	60,933,526	4,523,067	
4	Other	11,945,590	-988,485	
5	TOTAL (Enter Total of lines 2 thru 4)	305,474,214	14,543,106	
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	305,474,214	14,543,106	
10	Classification of TOTAL			
11	Federal Income Tax	295,780,791	13,591,688	
12	State Income Tax	9,693,423	951,418	
13	Local Income Tax			

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
						243,603,622	2
-130,820		282 Reclass	113			65,325,660	3
162,823				282 Reclass	113	11,120,041	4
32,003			113		113	320,049,323	5
							6
							7
							8
32,003			113		113	320,049,323	9
							10
32,003			113		113	309,404,482	11
						10,644,841	12
							13

NOTES (Continued)

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ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Electric	47,102,114	2,010,787	2,924,920
4				
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	47,102,114	2,010,787	2,924,920
10	Gas			
11	Gas	8,679,614	-5,888,963	9,882
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)	8,679,614	-5,888,963	9,882
18	Other	156,207,315	307,220	
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	211,989,043	-3,570,956	2,934,802
20	Classification of TOTAL			
21	Federal Income Tax	211,989,043	-3,570,956	2,934,802
22	State Income Tax			
23	Local Income Tax			

NOTES

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

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

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
[redacted]							1
[redacted]							2
1,910,045		182.3	325,496			47,772,530	3
							4
							5
							6
							7
							8
1,910,045			325,496			47,772,530	9
[redacted]							10
416,640		254	90,294	182.3	138,914	3,246,029	11
							12
							13
							14
							15
							16
416,640			90,294		138,914	3,246,029	17
-1,347,404	3,086,791	190 / 18	8,402,823	254/FAS	44,578,438	188,255,955	18
979,281	3,086,791		8,818,613		44,717,352	239,274,514	19
[redacted]							20
979,281	3,086,791		8,818,613		41,666,556	236,223,718	21
					3,050,796	3,050,796	22
							23

NOTES (Continued)

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $50,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Idaho Investment Tax Credit (254005)				7,120,008	7,120,008
2	Oregon BETC Credit (254010)				257,984	257,984
3	FAS 109 Invest Tax Credit (254180)	254,352	190180	26,556		227,796
4	Nez Perce (254220)	814,412	557200	22,008		792,404
5	Oregon Senate Bill (254250)	1,300,000			2,338,488	3,638,488
6	Unrealized Currenct Exchange (254399)				30,876	30,876
7	OPUC Investigate Reserve (254680)	478,043	Various	478,043		
8	Mark to Market FAS133 (254750)	15,400,153			38,013,630	53,413,783
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	18,246,960		526,607	47,760,986	65,481,339

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ELECTRIC OPERATING REVENUES (Account 400)

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

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	251,356,668	234,714,224
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	224,179,531	221,193,283
5	Large (or Ind.) (See Instr. 4)	95,206,943	92,960,960
6	(444) Public Street and Highway Lighting	5,516,824	5,268,037
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	856,061	849,076
10	TOTAL Sales to Ultimate Consumers	577,116,027	554,985,580
11	(447) Sales for Resale	138,609,644	175,572,595
12	TOTAL Sales of Electricity	715,725,671	730,558,175
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Prov. for Refunds	715,725,671	730,558,175
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	558,237	447,333
18	(453) Sales of Water and Water Power	309,017	230,504
19	(454) Rent from Electric Property	2,792,411	2,592,254
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	14,275,491	53,121,536
22	(456.1) Revenues from Transmission of Electricity of Others	10,470,726	10,605,281
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	28,405,882	66,996,908
27	TOTAL Electric Operating Revenues	744,131,553	797,555,083

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ELECTRIC OPERATING REVENUES (Account 400)

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

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
3,670,026	3,577,694	306,737	300,940	2
				3
3,132,068	3,109,861	38,488	37,912	4
2,084,372	2,061,888	1,377	1,388	5
25,418	24,783	426	425	6
				7
				8
12,842	12,776	69	67	9
8,924,726	8,787,002	347,097	340,732	10
2,536,103	3,552,362			11
11,460,829	12,339,364	347,097	340,732	12
				13
11,460,829	12,339,364	347,097	340,732	14

Line 12, column (b) includes $ 1,043,391 of unbilled revenues.

Line 12, column (d) includes 571 MWH relating to unbilled revenues

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	RESIDENTIAL SALES (440)					
2	1 Residential Service	3,527,294	231,334,355	293,436	12,021	0.0656
3	2 Residential Service					
4	3 Residential Service					
5	12 Res. & Farm Gen. Service	64,409	6,103,158	11,614	5,546	0.0948
6	15 MOPS II Residential					
7	22 Res. & Farm Lg. Gen. Service	49,285	3,126,329	94	524,309	0.0634
8	30 Pumping-Special					
9	32 Res. & Farm Pumping Service	14,080	984,252	1,593	8,839	0.0699
10	48 Res. & Farm Area Lighting	4,953	935,401			0.1889
11	49 Area Lighting-High-Press.	285	63,456			0.2227
12	56 Centralia Refund					
13	95 Wind Power		168,245			
14	72 Residential Service					
15	73 Residential Service					
16	74 Residential Service					
17	76 Residential Service					
18	77 Residential Service					
19	58A Tax Adjustment		-39,081			
20	58 Tax Adjustment		6,597,994			
21	SubTotal	3,660,306	249,274,109	306,737	11,933	0.0681
22	Residential-Unbilled	9,720	2,082,559			0.2143
23	Total Residential Sales	3,670,026	251,356,668	306,737	11,965	0.0685
24						
25	COMMERCIAL SALES (442)					
26	2 General Service					
27	3 General Service					
28	11 General Service	671,075	57,984,143	33,094	20,278	0.0864
29	12 Res. & Farm Gen. Service					
30	16 MOPS II Commercial					
31	19 Contract-General Service					
32	21 Large General Service	2,018,364	135,964,773	4,397	459,032	0.0674
33	25 Extra Lg. Gen. Service	349,703	16,154,594	13	26,900,231	0.0462
34	28 Contract-Extra Large Serv					
35	31 Pumping Service	93,179	5,745,491	984	94,694	0.0617
36	47 Area Lighting-Sod. Vap	6,909	1,150,169			0.1665
37	49 Area Lighting-High-Press.	2,294	407,074			0.1775
38	56 Centralia Refune					
39	95 Wind Power		53,089			
40	74 Large General Service					
41	TOTAL Billed	11,460,258	714,682,280	347,097	33,017	0.0624
42	Total Unbilled Rev.(See Instr. 6)	571	1,043,391	0	0	1.8273
43	TOTAL	11,460,829	715,725,671	347,097	33,019	0.0624

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SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	75 Large General Service					
2	76 Large General Service					
3	77 General Service					
4	58A Tax Adjustment		-41,450			
5	58 Tax Adjustment		7,789,511			
6	SubTotal	3,141,524	225,207,394	38,488	81,623	0.0717
7	Commercial-Unbilled	-9,456	-1,027,863			0.1087
8	Total Commercial	3,132,068	224,179,531	38,488	81,378	0.0716
9						
10	INDUSTRIAL SALES (442)					
11	2 General Service					
12	3 General Service					
13	8 Lg Gen Time of Use					
14	11 General Service	6,996	623,004	239	29,272	0.0891
15	12 Res. & Farm Gen. Service					
16	21 Large General Service	185,532	11,956,569	192	966,313	0.0644
17	25 Extra Lg. Gen. Service	1,805,207	76,570,340	23	78,487,261	0.0424
18	28 Contract - Extra Large Service	292	245,082	1	292,000	0.8393
19	29 Contract Lg. Gen. Service					
20	30 Pumping Service - Special	23,215	1,246,474	37	627,432	0.0537
21	31 Pumping Service	57,771	3,713,335	734	78,707	0.0643
22	32 Pumping Svc Res & Firm	4,775	306,379	151	31,623	0.0642
23	47 Area Lighting-Sod. Vap.	229	33,384			0.1458
24	49 Area Lighting - High-Press	47	7,709			0.1640
25	95 Wind Power		790			
26	72 General Service					
27	73 General Service					
28	74 Large General Service					
29	75 Large General Service					
30	76 Pumping Service					
31	77 General Service					
32	58A Tax Adjustment		-773			
33	58 Tax Adjustment		558,615			
34	SubTotal	2,084,064	95,260,908	1,377	1,513,481	0.0457
35	Industrial-Unbilled	308	-53,965			-0.1752
36	Total Industrial	2,084,372	95,206,943	1,377	1,513,705	0.0457
37						
38	STREET AND HWY LIGHTING (444)					
39	6 Mercury Vapor St. Ltg.					
40	7 HP Sodium Vap. St. Ltg					
41	TOTAL Billed	11,460,258	714,682,280	347,097	33,017	0.0624
42	Total Unbilled Rev.(See Instr. 6)	571	1,043,391	0	0	1.8273
43	TOTAL	11,460,829	715,725,671	347,097	33,019	0.0624

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SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	11 General Service					
2	41 Co-Owned St. Lt. Service	222	33,330	16	13,875	0.1501
3	42 Co-Owned St. Lt. Service	19,699	4,825,576	343	57,431	0.2450
4	High-Press. Sod. Vap.					
5	43 Cust-Owned St. Lt. Energy	35	2,892	1	35,000	0.0826
6	and Maint. Service					
7	44 Cust-Owned St. Lt. Energy	854	98,584	31	27,548	0.1154
8	and Maint. Svce - High-Pres					
9	Sodium Vapor					
10	45 Cust. Owned St. Lt. Energy Svc	1,351	75,676	8	168,875	0.0560
11	46 Cust. Owned St. Lt. Energy Svc	3,257	243,980	27	120,630	0.0749
12	58A Tax Adjustment		-493			
13	58 Tax Adjustment		194,619			
14	SubTotal	25,418	5,474,164	426	59,667	0.2154
15	Street & Hwy Lighting-Unbilled		42,660			
16	Total Street & Hwy Lighting	25,418	5,516,824	426	59,667	0.2170
17						
18	OTHER SALES TO PUBLIC					
19	(445)					
20	None					
21						
22	INTERDEPARTMENTAL SALES	12,842	856,061	69	186,116	0.0667
23	58 Tax Adjustment					
24	Total Interdepartmental	12,842	856,061	69	186,116	0.0667
25						
26	SALES FOR RESALE (447)	2,536,103	138,609,644			0.0547
27	61 Sales to Other Utilities (NDA)					
28						
29						
30	Total Sales for Resale	2,536,103	138,609,644			0.0547
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	11,460,258	714,682,280	347,097	33,017	0.0624
42	Total Unbilled Rev.(See Instr. 6)	571	1,043,391	0	0	1.8273
43	TOTAL	11,460,829	715,725,671	347,097	33,019	0.0624

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	BC Transmission Corp.	SF	Tariff 12			
2	Barclays Bank PLC	SF	WSPP-C			
3	Bear Energy LP	SF	WSPP-C			
4	Benton County Public Utility District	SF	WSPP-C			
5	Black Hills Power, Inc.	SF	WSPP-C			
6	BP Energy Company	SF	WSPP-C			
7	Bonneville Power Administration	LF	Tariff 8			
8	Bonneville Power Administration	LF	BPA OATT			
9	Bonneville Power Administration	SF	WSPP-C			
10	Bonneville Power Administration	SF	Tariff 12			
11	Cargill Power Markets, LLC	SF	WSPP-C			
12	Chelan County PUD No. 1	SF	WSPP-C			
13	Clatskanie Peoples PUD	SF	WSPP-C			
14	Conoco Phillips	SF	WSPP-C			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
85		5,092		5,092	1
85,546		4,391,791		4,391,791	2
6,400		360,850		360,850	3
1,231		62,140		62,140	4
75		4,169		4,169	5
153,552		7,618,220		7,618,220	6
30,414		1,654,670		1,654,670	7
1,672		87,454		87,454	8
14,072		527,437		527,437	9
37		1,921		1,921	10
98,081		4,816,407		4,816,407	11
1,800		91,400		91,400	12
143		3,510		3,510	13
444		30,183		30,183	14
0	0	0	0	0	
2,536,103	6,392,925	115,937,609	16,279,110	138,609,644	
2,536,103	**6,392,925**	**115,937,609**	**16,279,110**	**138,609,644**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Conoco Phillips	SF	Tariff 10			
2	Constellation Energy Commodities Group	SF	WSPP-C			
3	Coral Power, LLC	SF	WSPP-C			
4	Coral Power, LLC	SF	Tariff 10			
5	Douglas County PUD No. 1	SF	WSPP-C			
6	Enmax Energy Marketing, Inc.	SF	WSPP-C			
7	EPCOR Merchant & Capital US	SF	WSPP-C			
8	Eugene Water & Electric Board	SF	WSPP-C			
9	Fortis Energy Marketing & Trading GP	SF	WSPP-C			
10	Franklin County PUD No. 1	SF	WSPP-C			
11	Grant County PUD No. 2	SF	WSPP-C			
12	Grant County PUD No. 2	SF	Tariff 10			
13	Grays Harbor County PUD No. 1	SF	WSPP-C			
14	Highland Energy	SF	WSPP-C			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
	80,868			80,868	1
100,120		4,587,187		4,587,187	2
55,168		2,811,992		2,811,992	3
	1,400			1,400	4
656		31,425		31,425	5
125		11,200		11,200	6
2,664		138,130		138,130	7
3,075		156,425		156,425	8
14,400		837,400		837,400	9
567		30,495		30,495	10
15,208		730,130		730,130	11
	4,963			4,963	12
1,018		50,135		50,135	13
800		43,200		43,200	14
0	0	0	0	0	
2,536,103	6,392,925	115,937,609	16,279,110	138,609,644	
2,536,103	**6,392,925**	**115,937,609**	**16,279,110**	**138,609,644**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Hinson Power Company, LLC	SF	WSPP-C			
2	Idaho Power Company	SF	WSPP-C			
3	Idaho Power Company	SF	Tariff 12			
4	J. Aron & Company	SF	WSPP-C			
5	Klamath Falls, City of	SF	WSPP-C			
6	Lehman Brothers Commodity Services, Inc	SF	WSPP-C			
7	Modesto Irrigation District	SF	WSPP-C			
8	Morgan Stanley	SF	WSPP-C			
9	NorthWestern Energy LLC	SF	WSPP-C			
10	NorthWestern Energy LLC	SF	Tariff 10			
11	NorthWestern Energy LLC	LF	Tariff 9			
12	NorthWestern Energy LLC	IF	Tariff 10			
13	NorthWestern Energy LLC	IF	Tariff 10			
14	NorthWestern Energy LLC	IF	Tariff 9			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
1,600		127,200		127,200	1
37,212		1,577,397		1,577,397	2
87		4,600		4,600	3
23,375		1,629,941		1,629,941	4
1,271		33,201		33,201	5
42,825		2,019,731		2,019,731	6
7,739		421,300		421,300	7
149,883		8,065,264		8,065,264	8
6,824		380,807		380,807	9
	1,600,476			1,600,476	10
8,144		426,126		426,126	11
	1,727,495			1,727,495	12
			18,200	18,200	13
26,940		1,392,576		1,392,576	14
0	0	0	0	0	
2,536,103	6,392,925	115,937,609	16,279,110	138,609,644	
2,536,103	**6,392,925**	**115,937,609**	**16,279,110**	**138,609,644**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW) Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	NorthWestern Energy LLC	SF	Tariff 12			
2	Okanogan County PUD	SF	WSPP-C			
3	PNGC Power	SF	WSPP-C			
4	PacifiCorp	SF	WSPP-C			
5	PacifiCorp	SF	Tariff 12			
6	PacifiCorp	SF	Tariff 10			
7	PacifiCorp	LF	Tariff 9			
8	Peaker LLC	LF	Tariff 9			
9	Pend Oreille Public Utility District	IF	Tariff 10			
10	Pend Oreille Public Utility District	IF	Tariff 9			
11	Pend Oreille Public Utility District	SF	Tariff 10			
12	Pend Oreille Public Utility District	SF	Tariff 9			
13	Portland General Electric Company	SF	WSPP-C			
14	Portland General Electric Company	SF	Tariff 12			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
137		7,322		7,322	1
5,472		272,172		272,172	2
5,090		243,550		243,550	3
42,155		2,220,587		2,220,587	4
423		22,175		22,175	5
	5,500			5,500	6
5,182		271,171		271,171	7
	1,748,179			1,748,179	8
	420,936			420,936	9
5,628		282,209		282,209	10
	78,659			78,659	11
13,640		668,650		668,650	12
136,619		6,505,827		6,505,827	13
58		3,274		3,274	14
0	0	0	0	0	
2,536,103	6,392,925	115,937,609	16,279,110	138,609,644	
2,536,103	**6,392,925**	**115,937,609**	**16,279,110**	**138,609,644**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

SALES FOR RESALE (Account 447)

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

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

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
	3,800			3,800	1
149,613		6,164,523		6,164,523	2
	58,200			58,200	3
			11,200	11,200	4
	528,861			528,861	5
13,363		618,547		618,547	6
18,509		968,468		968,468	7
125,871		6,055,793		6,055,793	8
585		15,040		15,040	9
54,418		2,705,638		2,705,638	10
42		2,208		2,208	11
23,692		1,239,639		1,239,639	12
	3,950			3,950	13
49,769		2,667,471		2,667,471	14
0	0	0	0	0	
2,536,103	6,392,925	115,937,609	16,279,110	138,609,644	
2,536,103	**6,392,925**	**115,937,609**	**16,279,110**	**138,609,644**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

SALES FOR RESALE (Account 447)

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Redding, City of	SF	WSPP-C			
2	Sacramento Municipal Utility District	SF	WSPP-C			
3	Sacramento Municipal Utility District	LF	WSPP-C			
4	Seattle City Light	SF	WSPP-C			
5	Seattle City Light	SF	Tariff 12			
6	Sempra Energy Solutions	SF	WSPP-C			
7	Sempra Energy Trading	SF	WSPP-C			
8	Sierra Pacific Power Company	SF	WSPP-C			
9	Sierra Pacific Power Company	SF	Tariff 12			
10	Snohomish County PUD	SF	WSPP-C			
11	Sovereign Power	LF	Tariff 9			
12	Sovereign Power	LF	Tariff 10			
13	Suez Energy Marketing NA, Inc	SF	WSPP-C			
14	Tacoma Power	SF	WSPP-C			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
3,214		133,597		133,597	1
15,320		903,007		903,007	2
642,262		39,393,391		39,393,391	3
8,989		368,168		368,168	4
4		123		123	5
10,000		327,500		327,500	6
81,475		3,488,625		3,488,625	7
17,995		1,015,322		1,015,322	8
14		841		841	9
3,090		108,315		108,315	10
7,985		434,246		434,246	11
	101,353			101,353	12
10,100		489,519		489,519	13
5,003		209,715		209,715	14
0	0	0	0	0	
2,536,103	6,392,925	115,937,609	16,279,110	138,609,644	
2,536,103	**6,392,925**	**115,937,609**	**16,279,110**	**138,609,644**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

SALES FOR RESALE (Account 447)

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

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

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

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

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

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

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

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
	125			125	1
89,633		4,210,346		4,210,346	2
1,600		105,900		105,900	3
96,198		4,257,007		4,257,007	4
7		465		465	5
	28,160			28,160	6
			5,617	5,617	7
		-15,603,848	15,603,848		8
			661,661	661,661	9
-305			-21,416	-21,416	10
					11
					12
					13
					14
0	0	0	0	0	
2,536,103	6,392,925	115,937,609	16,279,110	138,609,644	
2,536,103	**6,392,925**	**115,937,609**	**16,279,110**	**138,609,644**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	271,720	255,226
5	(501) Fuel	26,719,429	25,443,765
6	(502) Steam Expenses	1,840,213	1,720,402
7	(503) Steam from Other Sources		16,016
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	835,130	783,473
10	(506) Miscellaneous Steam Power Expenses	2,068,116	1,794,317
11	(507) Rents	29,922	19,628
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	31,764,530	30,032,827
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	514,698	433,468
16	(511) Maintenance of Structures	496,664	504,566
17	(512) Maintenance of Boiler Plant	5,724,096	5,860,568
18	(513) Maintenance of Electric Plant	1,031,164	649,502
19	(514) Maintenance of Miscellaneous Steam Plant	723,773	702,446
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	8,490,395	8,150,550
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	40,254,925	38,183,377
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	1,657,569	1,567,952
45	(536) Water for Power	735,341	757,070
46	(537) Hydraulic Expenses	2,744,019	2,671,493
47	(538) Electric Expenses	4,515,089	4,507,784
48	(539) Miscellaneous Hydraulic Power Generation Expenses	718,330	746,756
49	(540) Rents	755,035	664,358
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	11,125,383	10,915,413
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	309,538	317,169
54	(542) Maintenance of Structures	336,239	296,564
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,368,818	604,461
56	(544) Maintenance of Electric Plant	2,114,811	2,318,232
57	(545) Maintenance of Miscellaneous Hydraulic Plant	150,450	451,650
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	4,279,856	3,988,076
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	15,405,239	14,903,489

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	1,202,574	1,016,705
63	(547) Fuel	99,775,888	85,535,646
64	(548) Generation Expenses	1,331,508	1,997,453
65	(549) Miscellaneous Other Power Generation Expenses	444,348	350,879
66	(550) Rents	21,779	32,436
67	TOTAL Operation (Enter Total of lines 62 thru 66)	102,776,097	88,933,119
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	942,204	62,892
70	(552) Maintenance of Structures	4,998	-847,959
71	(553) Maintenance of Generating and Electric Plant	1,749,571	1,646,847
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	160,317	171,398
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	2,857,090	1,033,178
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	105,633,187	89,966,297
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	191,126,248	200,083,219
77	(556) System Control and Load Dispatching	480,570	638,755
78	(557) Other Expenses	26,956,543	87,233,654
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	218,563,361	287,955,628
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	379,856,712	431,008,791
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,406,849	1,698,115
84	(561) Load Dispatching	-26,009	-6,011
85	(561.1) Load Dispatch-Reliability	16,212	16,212
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,165,928	1,165,928
87	(561.3) Load Dispatch-Transmission Service and Scheduling	770,853	770,853
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development		
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	166,599	274,938
94	(563) Overhead Lines Expenses	160,177	169,000
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	13,853,279	11,881,367
97	(566) Miscellaneous Transmission Expenses	878,319	718,741
98	(567) Rents	77,306	107,794
99	TOTAL Operation (Enter Total of lines 83 thru 98)	19,469,513	16,796,937
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	480,094	418,687
102	(569) Maintenance of Structures	324,247	193,198
103	(569.1) Maintenance of Computer Hardware		
104	(569.2) Maintenance of Computer Software		
105	(569.3) Maintenance of Communication Equipment		
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	990,440	1,115,863
108	(571) Maintenance of Overhead Lines	940,925	962,501
109	(572) Maintenance of Underground Lines	11,075	5,807
110	(573) Maintenance of Miscellaneous Transmission Plant	99,918	54,287
111	TOTAL Maintenance (Total of lines 101 thru 110)	2,846,699	2,750,343
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	22,316,212	19,547,280

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	1,086,493	914,176
135	(581) Load Dispatching		
136	(582) Station Expenses	456,006	399,676
137	(583) Overhead Line Expenses	872,105	748,605
138	(584) Underground Line Expenses	1,400,039	1,383,827
139	(585) Street Lighting and Signal System Expenses	209,843	173,361
140	(586) Meter Expenses	908,418	882,963
141	(587) Customer Installations Expenses	886,924	916,336
142	(588) Miscellaneous Expenses	4,614,263	4,385,283
143	(589) Rents	152,361	138,027
144	TOTAL Operation (Enter Total of lines 134 thru 143)	10,586,452	9,942,254
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	1,334,694	1,487,804
147	(591) Maintenance of Structures	269,664	263,589
148	(592) Maintenance of Station Equipment	872,990	920,003
149	(593) Maintenance of Overhead Lines	6,718,499	7,469,677
150	(594) Maintenance of Underground Lines	1,064,426	1,055,849
151	(595) Maintenance of Line Transformers	550,762	497,848
152	(596) Maintenance of Street Lighting and Signal Systems	559,751	389,891
153	(597) Maintenance of Meters	176,847	164,174
154	(598) Maintenance of Miscellaneous Distribution Plant	352,619	377,969
155	TOTAL Maintenance (Total of lines 146 thru 154)	11,900,252	12,626,804
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	22,486,704	22,569,058
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	533,668	511,548
160	(902) Meter Reading Expenses	2,138,197	2,415,032
161	(903) Customer Records and Collection Expenses	7,992,442	8,718,628
162	(904) Uncollectible Accounts	1,635,521	1,537,265
163	(905) Miscellaneous Customer Accounts Expenses	190,078	182,081
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	12,489,906	13,364,554

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	11,181,123	11,397,769
169	(909) Informational and Instructional Expenses	65,646	59,901
170	(910) Miscellaneous Customer Service and Informational Expenses	117,124	107,036
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	11,363,893	11,564,706
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	501,591	521,372
176	(913) Advertising Expenses	258,828	265,537
177	(916) Miscellaneous Sales Expenses	189,311	143,953
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	949,730	930,862
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	19,387,201	17,412,679
182	(921) Office Supplies and Expenses	3,633,500	4,217,501
183	(Less) (922) Administrative Expenses Transferred-Credit	34,969	28,056
184	(923) Outside Services Employed	11,687,401	9,988,121
185	(924) Property Insurance	1,128,497	1,191,391
186	(925) Injuries and Damages	3,289,641	3,769,353
187	(926) Employee Pensions and Benefits	991,605	1,106,169
188	(927) Franchise Requirements	6,327	6,230
189	(928) Regulatory Commission Expenses	4,315,148	1,887,178
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	9,097	8,678
192	(930.2) Miscellaneous General Expenses	3,092,795	2,950,213
193	(931) Rents	698,836	1,068,064
194	TOTAL Operation (Enter Total of lines 181 thru 193)	48,205,079	43,577,521
195	Maintenance		
196	(935) Maintenance of General Plant	7,127,608	5,940,101
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	55,332,687	49,517,622
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	504,795,844	548,502,873

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	BP Energy Comp	IF	WSPP			
2	BP Energy Comp	SF	WSPP			
3	Barclays Bank PLC	SF	WSPP			
4	Bear Energy	SF	WSPP			
5	Benton County PUD No. 1	SF	WSPP			
6	Black Creek Hydro	LU	FERC #1			
7	Black Hills Power	SF	WSPP			
8	Bonneville Power Administration	LF	WNP#3 Agr.			
9	Bonneville Power Administration	SF	WSPP			
10	Bonneville Power Administration	EX	PNCA			
11	Bonneville Power Administration	SF	Tariff #8			
12	Bonneville Power Administration	OS	BPA OATT			
13	Bonneville Power Administration	SF	BPA OATT			
14	Cargill Power Markets, LLC	SF	WSPP			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
219,000				7,555,500		7,555,500	1
72,600				4,322,220		4,322,220	2
28,400				1,462,516		1,462,516	3
78,200				4,644,650		4,644,650	4
2,305				119,225		119,225	5
2,959				144,069		144,069	6
400				24,600		24,600	7
339,510				11,869,886		11,869,886	8
75,389				3,713,762		3,713,762	9
	44,160	43,425		182,378	38,410	220,788	10
38,295				1,893,314		1,893,314	11
					1,026,306	1,026,306	12
20,626				1,192,593	232,788	1,425,381	13
30,007				1,591,280		1,591,280	14
4,761,534	974,470	974,494	605	189,859,425	1,266,216	191,126,246	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Chelan County PUD No. 1	LU	Rocky Reach			
2	Chelan County PUD No. 1	SF	WSPP			
3	City of Klamath Falls	SF	WSPP			
4	City of Spokane	LU	PURPA			
5	Clatskanie Peoples PUD	SF	WSPP			
6	Conoco	SF	WSPP			
7	Columbia Power Storage Exch	OS	CSPE			
8	Constellation Energy Commodities Group	SF	WSPP			
9	Coral Power	SF	WSPP			
10	Douglas County PUD No. 1	LU	Wells			
11	Douglas County PUD No. 1	LU	Wells Settlement			
12	Douglas County PUD No. 1	SF	WSPP			
13	Douglas County PUD No. 1	EX	305			
14	EPCOR Merchant & Capital US	SF	WSPP			
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
180,517				2,180,821		2,180,821	1
7,607				400,936		400,936	2
4,687				240,650		240,650	3
49,278				1,913,150		1,913,150	4
473				26,752		26,752	5
75				4,275		4,275	6
					-1,299	-1,299	7
30,494				1,675,116		1,675,116	8
42,236				2,171,928		2,171,928	9
126,978				1,274,896		1,274,896	10
34,628				616,567		616,567	11
59,742				3,533,493		3,533,493	12
	124,560	124,504		1,493,500	5,117	1,498,617	13
17,304				1,080,130		1,080,130	14
4,761,534	974,470	974,494	605	189,859,425	1,266,216	191,126,246	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Eugene Water & Electric Board	SF	WSPP			
2	Fortis Energy Mkt	SF	WSPP			
3	Ford Hydro Limited Partnership	LU	PURPA			
4	Franklin County PUD No. 1	SF	WSPP			
5	Grant County PUD No. 2	LU	Wanapum			
6	Grant County PUD No. 2	LU	Priest Rapids			
7	Grant County PUD No. 2	LU	PR Displacement			
8	Grant County PUD No. 2	SF	WSPP			
9	Grant County PUD No. 2	IF	Grant PUD			
10	Grays Harbor County PUD No. 1	SF	WSPP			
11	Highland Energy	IU	WSPP			
12	Hydro Technology Systems	LU	PURPA			
13	Idaho Power Company	SF	WSPP			
14	Inland Power & Light Company	RQ	208			
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
27,628				1,329,205		1,329,205	1
39,000				1,717,820		1,717,820	2
3,027				175,250		175,250	3
958				48,341		48,341	4
356,599				4,429,564		4,429,564	5
133,839				3,924,158		3,924,158	6
194,149				5,609,665		5,609,665	7
43,482				2,101,077		2,101,077	8
			280	275,854		276,134	9
1,179				62,878		62,878	10
1,525				82,500		82,500	11
8,090				368,941		368,941	12
16,030				790,145		790,145	13
146				7,665		7,665	14
4,761,534	974,470	974,494	605	189,859,425	1,266,216	191,126,246	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	J Aron	SF	WSPP			
2	Jim White	LU	PURPA			
3	John Day Hydro	LU	PURPA			
4	Kalich, Clint	LU	PURPA			
5	Lehman Bothers	SF	WSPP			
6	Los Angeles Dept Water and Power	SF	WSPP			
7	Mirant Energy Trading	SF	WSPP			
8	Morgan Stanley Capital Group	IF	WSPP			
9	Morgan Stanley Capital Group	SF	WSPP			
10	NorthWestern Energy LLC	SF	WSPP			
11	Okanogan County PUD No. 1	SF	WSPP			
12	PPL Montana, LLC	SF	WSPP			
13	PPM Energy	LU	PPM Energy			
14	PPM Energy	SF	WSPP			
	Total					

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
30,400				2,021,600		2,021,600	1
1,202				99,711		99,711	2
1,669				65,279		65,279	3
				47		47	4
77,120				3,944,601		3,944,601	5
350				29,575		29,575	6
3,200				209,100		209,100	7
657,000				20,191,800		20,191,800	8
52,663				2,617,895		2,617,895	9
30,765				1,576,229		1,576,229	10
53,024				2,944,485		2,944,485	11
350,890				17,702,833		17,702,833	12
80,049				3,102,661		3,102,661	13
32,685				2,098,129		2,098,129	14
4,761,534	974,470	974,494	605	189,859,425	1,266,216	191,126,246	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	PacifiCorp	SF	WSPP			
2	Pacific NW Gen Corp	SF	WSPP			
3	Pend Oreille County PUD No. 1	SF	Pend O'			
4	Pend Oreille County PUD No. 1	SF	Pend O'			
5	Pend Oreille County PUD No. 1	EX	PNCA			
6	Phillips Ranch	LU	PURPA			
7	Portland General Electric Company	EX	304			
8	Portland General Electric Company	EX	178			
9	Portland General Electric Company	EX	WSPP			
10	Portland General Electric Company	SF	WSPP			
11	Potlatch Corporation	LU	PURPA			
12	Powerex Corp	SF	WSPP			
13	Public Service of Colorado	SF	WSPP			
14	Puget Sound Energy	SF	WSPP			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
43,051			200	2,311,917		2,312,117	1
12,934				655,615		655,615	2
1,762				203,210		203,210	3
110,879				5,327,113		5,327,113	4
	25,805	26,161			-5,092	-5,092	5
44				1,790		1,790	6
	10,352	10,362					7
	453,118	453,515			-30,014	-30,014	8
	206,875	206,875		1,533,000		1,533,000	9
45,042				2,392,280		2,392,280	10
462,755				19,861,445		19,861,445	11
76,336				3,847,027		3,847,027	12
440				25,800		25,800	13
24,864				1,366,538		1,366,538	14
4,761,534	974,470	974,494	605	189,859,425	1,266,216	191,126,246	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Rainbow Energy Marketing Corp	SF	WSPP			
2	Sacramento Municipal Utility District	SF	WSPP			
3	Seattle City Light	SF	WSPP			
4	Seattle City Light	EX	WSPP			
5	Sempra Energy Trading	SF	WSPP			
6	Sheep Creek Hydro	LU	PURPA			
7	Sierra Pacific Power Company	SF	WSPP			
8	Snohomish County PUD No. 1	SF	WSPP			
9	Sovereign Power	IF	Sovereign			
10	Stimson Lumber	IU	PURPA			
11	Tacoma Power	SF	WSPP			
12	The Energy Authority	SF	WSPP			
13	TransAlta Energy Marketing	SF	WSPP			
14	Tucson Electric	SF	WSPP			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
78,283				4,220,996		4,220,996	1
250				12,650		12,650	2
36,944				2,063,314		2,063,314	3
	109,600	109,600		1,680,600		1,680,600	4
45,460				2,577,356		2,577,356	5
6,091				379,962		379,962	6
738				42,340		42,340	7
4,775				248,620		248,620	8
4,603				120,613		120,613	9
37,314				1,990,145		1,990,145	10
19,938			125	1,011,501		1,011,626	11
5,503				310,032		310,032	12
41,204				1,960,442		1,960,442	13
33				1,485		1,485	14
4,761,534	974,470	974,494	605	189,859,425	1,266,216	191,126,246	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Turlock irrigation Dist	SF	WSPP			
2	UBS AG	SF	WSPP			
3	WAPA	SF	WSPP			
4	IntraCompany Generation Services	OS	OATT			
5	Other - Inadvertent Interchange	EX				
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
110				8,580		8,580	1
43,800				2,188,070		2,188,070	2
2				108		108	3
				661,661		661,661	4
		52					5
							6
							7
							8
							9
							10
							11
							12
							13
							14
4,761,534	974,470	974,494	605	189,859,425	1,266,216	191,126,246	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Avista Energy	NorthWestern Montana	Chelan Public Utility District	NF
2	Avista Energy	Chelan Public Utility District	Idaho Power Company	NF
3	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	FNO
4	Bonneville Power Administration	Bonneville Power Administration	Idaho Power Company	NF
5	Bonneville Power Administration	Bonneville Power Administration	NorthWestern Montana	NF
6	Bonneville Power Administration	Bonneville Power Administration	Idaho Power Company	SFP
7	Consolidated Irrigation District	Bonneville Power Administration	Consolidated Irrigation District	LFP
8	Grant County PUD	Grant County PUD	Grant County PUD	LFP
9	PPL Montana	NorthWestern Montana	Chelan Public Utility District	NF
10	PPL Montana	NorthWestern Montana	Grant County Public Utility Dist	NF
11	PPL Montana	NorthWestern Montana	Idaho Power Company	NF
12	PPL Montana	NorthWestern Montana	Bonneville Power Administration	NF
13	Idaho Power Company	Portland General Electric	Idaho Power Company	NF
14	Idaho Power Company	Puget Sound Energy	Idaho Power Company	NF
15	Idaho Power Company	Grant County Public Utility Dist	Idaho Power Company	NF
16	Idaho Power Company	Idaho Power Company	Chelan Public Utility District	NF
17	Idaho Power Company	Idaho Power Company	Bonneville Power Administration	NF
18	Idaho Power Company	Chelan Public Utility District	NorthWestern Montana	NF
19	Idaho Power Company	Bonneville Power Administration	Idaho Power Company	NF
20	Idaho Power Company	Chelan Public Utility District	Idaho Power Company	NF
21	Idaho Power Company	Bonneville Power Administration	Idaho Power Company	SFP
22	Idaho Power Company	Grant County Public Utility Dist	Idaho Power Company	SFP
23	Idaho Power Company	Grant County Public Utility Dist	NorthWestern Montana	SFP
24	Idaho Power Company	PacifiCorp	Idaho Power Company	SFP
25	Idaho Power Company	PacifiCorp	NorthWestern Montana	SFP
26	Idaho Power Company	Chelan Public Utility District	Idaho Power Company	SFP
27	NorthWestern Montana	NorthWestern Montana	Idaho Power Company	SFP
28	NorthWestern Energy	NorthWestern Montana	Bonneville Power Administration	NF
29	NorthWestern Energy	NorthWestern Montana	Puget Sound Energy	NF
30	NorthWestern Energy	NorthWestern Montana	Chelan Public Utility District	NF
31	NorthWestern Energy	NorthWestern Montana	Portland General Electric	NF
32	NorthWestern Energy	NorthWestern Montana	Idaho Power Company	SFP
33	PacifiCorp	PacifiCorp	Idaho Power Company	NF
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
FERC Trf No. 8				1,098	1,098	1
FERC Trf No. 8				915	915	2
FERC Trf No. 8				1,825,106	1,825,106	3
FERC Trf No. 8				24,468	24,468	4
FERC Trf No. 8				5	5	5
FERC Trf No. 8				39,483	39,483	6
FERC Trf No. 8	Bell Substation	Consolidated	4	6,529	6,529	7
FERC No. 104	Larson Substation	Round Lk Coulee City	25	92,613	92,613	8
FERC Trf No. 8				450	450	9
FERC Trf No. 8				75	75	10
FERC Trf No. 8				1,255	1,255	11
FERC Trf No. 8				4,449	4,449	12
FERC Trf No. 8				1,140	1,140	13
FERC Trf No. 8				3,473	3,473	14
FERC Trf No. 8				1,287	1,287	15
FERC Trf No. 8				75	75	16
FERC Trf No. 8				12,142	12,142	17
FERC Trf No. 8				200	200	18
FERC Trf No. 8				191,744	191,744	19
FERC Trf No. 8				1,904	1,904	20
FERC Trf No. 8				318,978	318,978	21
FERC Trf No. 8				860	860	22
FERC Trf No. 8				400	400	23
FERC Trf No. 8				400	400	24
FERC Trf No. 8				400	400	25
FERC Trf No. 8				793	793	26
FERC Trf No. 8				1,230	1,230	27
FERC Trf No. 8				736	736	28
FERC Trf No. 8				115	115	29
FERC Trf No. 8				124	124	30
FERC Trf No. 8				55	55	31
FERC Trf No. 8						32
FERC Trf No. 8				64	64	33
						34
			218	**3,553,693**	**3,553,693**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	4,431		4,431	1
	3,761		3,761	2
5,006,501			5,006,501	3
	99,774		99,774	4
	30		30	5
108,040			108,040	6
35,448			35,448	7
27,394			27,394	8
	1,855		1,855	9
	304		304	10
	5,160		5,160	11
	18,209		18,209	12
	4,559		4,559	13
	13,084		13,084	14
	4,991		4,991	15
	298		298	16
	45,443		45,443	17
	800		800	18
	760,001		760,001	19
	7,521		7,521	20
807,195			807,195	21
3,230			3,230	22
2,562			2,562	23
2,562			2,562	24
2,562			2,562	25
5,079			5,079	26
9,690			9,690	27
	3,115		3,115	28
	523		523	29
	672		672	30
	222		222	31
29,400			29,400	32
	4,756		4,756	33
				34
8,827,654	**1,588,539**	**54,534**	**10,470,727**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	PacifiCorp	Idaho Power Company	PacifiCorp	SFP
2	PacifiCorp	PacifiCorp	Bonneville Power Administration	NF
3	PacifiCorp	NorthWestern Montana	Bonneville Power Administration	NF
4	PacifiCorp	Idaho Power Company	Bonneville Power Administration	NF
5	Powerex	NorthWestern Montana	Bonneville Power Administration	NF
6	Powerex	Idaho Power Company	Bonneville Power Administration	NF
7	Powerex	NorthWestern Montana	Idaho Power Company	NF
8	Powerex	Bonneville Power Administration	Bonneville Power Administration	NF
9	Powerex	Bonneville Power Administration	Idaho Power Company	NF
10	Powerex	NorthWestern Montana	Idaho Power Company	SFP
11	Powerex	Bonneville Power Administration	Idaho Power Company	SFP
12	Powerex	NorthWestern Montana	Bonneville Power Administration	SFP
13	Puget Sound Energy	Puget Sound Energy	Idaho Power Company	NF
14	Puget Sound Energy	NorthWestern Montana	Puget Sound Energy	NF
15	Puget Sound Energy	NorthWestern Montana	Bonneville Power Administration	NF
16	Seattle City Light	Bonneville Power Administration	Idaho Power Company	NF
17	Portland General Electric	NorthWestern Montana	Portland General Electric	NF
18	Portland General Electric	NorthWestern Montana	Bonneville Power Administration	SFP
19	Portland General Electric	NorthWestern Montana	Portland General Electric	SFP
20	Morgan Stanley Capital Group	Puget Sound Energy	Idaho Power Company	NF
21	Morgan Stanley Capital Group	Bonneville Power Administration	Idaho Power Company	NF
22	Morgan Stanley Capital Group	Idaho Power Company	Bonneville Power Administration	NF
23	Sierra Pacific Power Company	Bonneville Power Administration	Idaho Power Company	NF
24	Sierra Pacific Power Company	Grant County Public Utility Dist	Idaho Power Company	NF
25	Sierra Pacific Power Company	Chelan Public Utility District	Idaho Power Company	NF
26	Sierra Pacific Power Company	Portland General Electric	Idaho Power Company	NF
27	Sierra Pacific Power Company	Chelan Public Utility District	NorthWestern Montana	NF
28	Sierra Pacific Power Company	Idaho Power Company	Chelan Public Utility District	NF
29	Sierra Pacific Power Company	NorthWestern Montana	Idaho Power Company	NF
30	Sierra Pacific Power Company	Puget Sound Energy	Idaho Power Company	NF
31	Sierra Pacific Power Company	Bonneville Power Administration	Idaho Power Company	SFP
32	Sierra Pacific Power Company	Grant County Public Utility Dist	Idaho Power Company	SFP
33	Sierra Pacific Power Company	NorthWestern Montana	Idaho Power Company	SFP
34				
	TOTAL			

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
FERC Trf No. 8				7,025	7,025	1
FERC Trf No. 8				2,368	2,368	2
FERC Trf No. 8				200	200	3
FERC Trf No. 8						4
FERC Trf No. 8				6,397	6,397	5
FERC Trf No. 8				3,337	3,337	6
FERC Trf No. 8				361	361	7
FERC Trf No. 8				10	10	8
FERC Trf No. 8				21,672	21,672	9
FERC Trf No. 8				9,147	9,147	10
FERC Trf No. 8				18,053	18,053	11
FERC Trf No. 8				4,835	4,835	12
FERC Trf No. 8				132	132	13
FERC Trf No. 8				1,400	1,400	14
FERC Trf No. 8				983	983	15
FERC Trf No. 8				30	30	16
FERC Trf No. 8				14,862	14,862	17
FERC Trf No. 8				6,760	6,760	18
FERC Trf No. 8						19
FERC Trf No. 8				100	100	20
FERC Trf No. 8				5,874	5,874	21
FERC Trf No. 8				336	336	22
FERC Trf No. 8				41,385	41,385	23
FERC Trf No. 8				240	240	24
FERC Trf No. 8				6,316	6,316	25
FERC Trf No. 8				390	390	26
FERC Trf No. 8				500	500	27
FERC Trf No. 8				50	50	28
FERC Trf No. 8				4,058	4,058	29
FERC Trf No. 8				100	100	30
FERC Trf No. 8				77,250	77,250	31
FERC Trf No. 8				160	160	32
FERC Trf No. 8				582	582	33
						34
			218	**3,553,693**	**3,553,693**	

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
62,016			62,016	1
	19,504		19,504	2
	800		800	3
	400		400	4
	29,004		29,004	5
	13,155		13,155	6
	1,373		1,373	7
	48		48	8
	104,903		104,903	9
27,143			27,143	10
258,569			258,569	11
29,393			29,393	12
	553		553	13
	6,124		6,124	14
	4,048		4,048	15
	160		160	16
	63,120		63,120	17
34,198			34,198	18
39,406			39,406	19
	400		400	20
	22,864		22,864	21
	1,344		1,344	22
	157,984		157,984	23
	960		960	24
	23,503		23,503	25
	1,560		1,560	26
	2,088		2,088	27
	200		200	28
	16,702		16,702	29
	325		325	30
241,970			241,970	31
448			448	32
4,747			4,747	33
				34
8,827,654	**1,588,539**	**54,534**	**10,470,727**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Sierra Pacific Power Company	PacifiCorp	Idaho Power Company	SFP
2	Sierra Pacific Power Company	Puget Sound Energy	Idaho Power Company	SFP
3	Cargill Power Markets	Idaho Power Company	Bonneville Power Administration	NF
4	Cargill Power Markets	NorthWestern Montana	Idaho Power Company	NF
5	Cargill Power Markets	Bonneville Power Administration	Idaho Power Company	NF
6	Cargill Power Markets	Chelan Public Utility District	Idaho Power Company	NF
7	Cargill Power Markets	Bonneville Power Administration	Idaho Power Company	SFP
8	Rainbow Energy Marketing Corp	Bonneville Power Administration	Idaho Power Company	NF
9	Sempra Energy Trading Corp.	Bonneville Power Administration	Idaho Power Company	NF
10	Sempra Energy Trading Corp.	NorthWestern Montana	Idaho Power Company	NF
11	Sempra Energy Trading Corp.	NorthWestern Montana	PacifiCorp	NF
12	Sempra Energy Trading Corp.	Bonneville Power Administration	Idaho Power Company	SFP
13	Sempra Energy Trading Corp.	NorthWestern Montana	Idaho Power Company	SFP
14	Sempra Energy Trading Corp.	NorthWestern Montana	Bonneville Power Administration	SFP
15	Coral Power	NorthWestern Montana	Chelan Public Utility District	NF
16	Coral Power	Idaho Power Company	Bonneville Power Administration	NF
17	Coral Power	Idaho Power Company	Chelan Public Utility District	NF
18	PPL Energy Plus	Grant County Public Utility Dist	NorthWestern Montana	NF
19	PPL Energy Plus	NorthWestern Montana	Bonneville Power Administration	NF
20	Vaagen Bros Lumber	Vaagen Bros Lumber	Idaho Power Company	LFP
21	Pacificorp	Pacificorp	Pacificorp	LFP
22	Seattle City Light	Seattle City Light	Bonneville Power Administration	LFP
23	Tacoma Power	Tacoma Power	Bonneville Power Administration	LFP
24	Spokane Indian Tribes	Bonneville Power Administration	Spokane Indian Tribes	LFP
25	USBR	Bonneville Power Administration	East Greenacres	LFP
26	City of Spokane	City of Spokane	Puget Sound Energy	LFP
27	NorthWestern Energy	Avista Corporation	NorthWestern Energy	LFP
28	NorthWestern Energy	Avista Corporation	NorthWestern Energy	LFP
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
FERC Trf No. 8				640	640	1
FERC Trf No. 8				400	400	2
FERC Trf No. 8				678	678	3
FERC Trf No. 8				191	191	4
FERC Trf No. 8				9,220	9,220	5
FERC Trf No. 8				400	400	6
FERC Trf No. 8				4,000	4,000	7
FERC Trf No. 8				32	32	8
FERC Trf No. 8				2,403	2,403	9
FERC Trf No. 8				402	402	10
FERC Trf No. 8				349	349	11
FERC Trf No. 8				16,286	16,286	12
FERC Trf No. 8				536	536	13
FERC Trf No. 8				110	110	14
FERC Trf No. 8				9,953	9,953	15
FERC Trf No. 8				36	36	16
FERC Trf No. 8				337	337	17
FERC Trf No. 8				100	100	18
FERC Trf No. 8				2,672	2,672	19
FERC No. 228	Colville Substation	Lolo-Oxbow 230 kv	4	20,370	20,370	20
FERC No. 182	Lolo-Oxbow 230 kv	Dry Gulch	20	64,108	64,108	21
FERC Trf No. 8	Main Canal/Summer Fs	Bell Substation	61	240,345	240,345	22
FERC Trf No. 8	Main Canal/Summer Fs	Bell Substation	61	240,345	240,345	23
FERC Trf No. 8	Sunset	Westside	2	3,129	3,129	24
FERC No. 80.2	Bell Substation	East Greenacres	3	3,555	3,555	25
No 155	Sunset-Westside 115k	Westside	23	141,747	141,747	26
FERC Trf No. 8	Cabinet Gorge	Hot Springs	10	15,993	15,993	27
FERC Trf No. 8	Chelan PUD	Hot Springs	5	7,877	7,877	28
						29
						30
						31
						32
						33
						34
			218	**3,553,693**	**3,553,693**	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
1,793			1,793	1
1,121			1,121	2
	3,200		3,200	3
	851		851	4
	42,733		42,733	5
	1,600		1,600	6
16,150			16,150	7
	128		128	8
	12,422		12,422	9
	1,540		1,540	10
	1,396		1,396	11
77,592			77,592	12
2,440			2,440	13
501			501	14
	40,762		40,762	15
	145		145	16
	1,354		1,354	17
	411		411	18
	10,996		10,996	19
67,488	20,370	22,446	110,304	20
252,340			252,340	21
640,500			640,500	22
640,500			640,500	23
14,582			14,582	24
16,588			16,588	25
127,506		32,088	159,594	26
154,770			154,770	27
76,230			76,230	28
				29
				30
				31
				32
				33
				34
8,827,654	**1,588,539**	**54,534**	**10,470,727**	

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Bonneville Power Admin	LFP			1,172,808			1,172,808
2	Bonneville Power Admin	LFP			7,821,982			7,821,982
3	Bonneville Power Admin	LFP			789,714			789,714
4	Bonneville Power Admin	FNS			958,779		381,647	1,340,426
5	Bonneville Power Admin	OS			24,360		-285,432	-261,072
6	Bonneville Power Admin	SFP					97,645	97,645
7	Bonneville Power Admin	NF	11,228	11,228		48,722		48,722
8	Grant PUD	LFP			512,400		10,972	523,372
9	Kootenai Electric Coop	LFP			32,112			32,112
10	Northern Lights	LFP			89,011			89,011
11	NorthWestern Energy	NF	27,595	27,595		133,461		133,461
12	Northwestern Energy	SFP			262,000			262,000
13	Portland General Elec	LFP			642,588			642,588
14	Portland General Elec	SFP						
15	Portland General Elec	NF	50	50		83	-194	-111
16	Puget Sound Energy	NF	2,959	2,959		17,754		17,754
	TOTAL		491,054	491,054	12,305,754	1,342,886	204,638	13,853,278

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Seattle City Light	NF	30,018	30,018		94,347		94,347
2	Snohomish PUD	NF	410,248	410,248		1,021,749		1,021,749
3	Tacoma Power	NF	8,956	8,956		26,770		26,770
4	TOTAL		491,054	491,054	12,305,754	1,342,886	204,638	13,853,278
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		491,054	491,054	12,305,754	1,342,886	204,638	13,853,278

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	533,135
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	78,237
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	1,270,420
6	Community Relations	416,421
7	Education and Informational	74,954
8	Other Miscellaneous General Expenses	241,024
9	Directors Fees and Expenses	464,828
10	Consulting Fees	13,776
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
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44		
45		
46	TOTAL	3,092,795

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			2,412,903		2,412,903
2	Steam Production Plant	11,519,867				11,519,867
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	6,515,195				6,515,195
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	10,586,287			2,450,031	13,036,318
7	Transmission Plant	9,835,012				9,835,012
8	Distribution Plant	18,445,167				18,445,167
9	Regional Transmission and Market Operation					
10	General Plant	3,450,887				3,450,887
11	Common Plant-Electric	4,164,695		823,839		4,988,534
12	TOTAL	64,517,110		3,236,742	2,450,031	70,203,883

B. Basis for Amortization Charges

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	STEAM PLANT						
13	Colstrip No. 3						
14	311	50,415	35.62	-6.30	2.93		11.52
15	312	74,830	35.96	-6.80	3.12		12.51
16	314	19,016	34.03	-6.40	3.10		17.73
17	315	9,357	35.37	-6.40	2.76		15.20
18	316	8,779	34.15	-5.50	2.73		12.47
19	Subtotal	162,397					
20							
21	Colstrip No. 4						
22	311	49,564	33.73	-6.30	2.95		12.82
23	312	46,749	34.03	-6.90	3.11		14.34
24	314	15,379	31.79	-6.40	3.11		16.74
25	315	6,676	34.54	-7.00	2.80		17.63
26	316	4,153	32.63	-5.50	2.81		14.54
27	Subtotal	122,521					
28							
29	Kettle Falls						
30	310	148	35.00		3.01		
31	311	24,562	33.01	-3.80	3.09		11.79
32	312	40,261	33.50	-4.10	3.26		14.53
33	314	13,187	33.81	-3.70	3.25		13.23
34	315	10,265	34.31	-4.20	2.96		12.66
35	316	2,321	33.08	-3.10	2.99		14.88
36	Subtotal	90,744					
37							
38	HYDRO PLANT						
39	Cabinet Gorge						
40	330	7,604	100.00			SQ	92.13
41	331	10,014	75.00	1.10	0.07	S2	39.49
42	332	23,573	100.00	-5.80	0.05	R3	75.40
43	333	34,680	60.00	0.50	0.10	S3	53.68
44	334	5,380	45.00	56.60	0.37	R3	15.89
45	335	2,416	45.00	-1.20	0.39	R3	0.64
46	336	1,099	75.00		0.09	R3	23.40
47	Subtotal	84,766				9% Sinking Fund	
48							
49	Noxon Rapids						
50	330	29,974	100.00			SQ	94.97

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	331	12,421	75.00	5.70	0.07	S2	58.34
13	332	31,776	100.00	64.10	0.04	R3	79.08
14	333	36,908	60.00	-1.30	0.10	S3	56.44
15	334	12,996	45.00	-16.20	0.37	R3	44.92
16	335	2,691	45.00	-5.50	0.39	R2	14.55
17	336	225	65.00		0.09	R3	46.05
18	Subtotal	126,991				9% Sinking Fund	
19							
20	Post Falls						
21	330	2,732	100.00			SQ	80.80
22	331	837	65.00	-8.90	0.07	S2	24.15
23	332	6,045	90.00	0.70	0.04	R3	86.20
24	333	2,232	60.00		0.10	S3	0.08
25	334	877	40.00	-11.60	0.37	R3	0.45
26	335	219	55.00	5.50	0.39	R2	47.88
27	Subtotal	12,942				9% Sinking Fund	
28							
29	Long Lake						
30	330	418	100.00			SQ	65.03
31	331	1,677	75.00	-110.50	0.07	S2	5.75
32	332	16,638	95.00	6.20	0.04	R3	24.17
33	333	8,824	60.00	-28.80	0.10	S3	14.68
34	334	2,822	45.00	122.10	0.37	R3	5.41
35	335	392	45.00	27.80	0.39	R2	19.58
36	Subtotal	30,771				9% Sinking Fund	
37							
38	Little Falls						
39	330	4,217	100.00			SQ	76.96
40	331	920	75.00	13.20	0.07	S2	
41	332	5,025	95.00	-0.50	0.04	R3	50.79
42	333	3,969	60.00	-4.20	0.10	S3	
43	334	1,853	40.00	18.00	0.37	R3	11.73
44	335	141	55.00	-1.70	0.39	R2	17.11
45	Subtotal	16,125				9% Sinking Fund	
46							
47	Upper Falls						
48	330	64	100.00			SQ	56.59
49	331	492	75.00	-1.70	0.07	S2	
50	332	7,125	95.00	14.70	0.04	R3	75.70

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	333	1,113	60.00	-201.60	0.10	S3	11.63
13	334	776	45.00	-1.00	0.37	R3	26.26
14	335	107	35.00		0.39	R2	29.18
15	Subtotal	9,677				9% Sinking Fund	
16							
17	Nine Mile						
18	330	11	100.00			SQ	47.72
19	331	3,943	75.00	-12.00	0.07	S2	56.58
20	332	11,841	95.00	-12.90	0.04	R3	70.96
21	333	9,465	60.00	-18.00	0.10	S3	58.16
22	334	2,637	45.00	24.60	0.37	R3	32.67
23	335	286	55.00	-0.70	0.39	R2	40.16
24	336	625	65.00		0.09	R3	62.78
25	Subtotal	28,808				9% Sinking Fund	
26							
27	Monroe Street						
28	331	8,399	65.00	-31.20	0.07	R3	-201.60
29	332	8,045	75.00	-34.90	0.40	S2	75.70
30	333	11,018	60.00	-32.70	0.10	S3	61.60
31	334	1,652	45.00	-31.30	0.37	R3	46.47
32	335	34	45.00	-35.70	0.39	R2	45.48
33	336	50	65.00	-13.20	0.09	R3	65.78
34	Subtotal	29,198				9% Sinking Fund	
35							
36	OTHER PRODUCTION						
37	Northeast Turbine						
38	341	257	29.33		2.36		
39	342	32	29.98		2.08		9.89
40	343	9,089	29.78		2.21		8.00
41	344	2,600	29.93		2.18		0.12
42	345	392	16.60		7.34		6.63
43	346	284	29.35		2.61		7.19
44	Subtotal	12,654					
45							
46	Rathdrum Turbine						
47	341	3,187	25.00		3.95		23.72
48	342	1,700	30.00		3.37		28.71
49	343	3,658	50.00		3.61		40.83
50	344	48,604	45.00		3.37		42.94

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	345	1,869	40.00		3.56		37.53
13	Subtotal	59,018					
14							
15	Kettle Falls CT						
16	342	89			4.17		19.40
17	343	9,071			4.18		19.34
18	344	4			2.18		21.46
19	345	5			4.20		19.23
20	Subtotal	9,169					
21							
22	Boulder Park						
23	341	725			5.00		15.37
24	342	116			5.00		15.33
25	343	57			5.00		17.68
26	344	30,093			4.14		19.38
27	345	278			5.00		15.88
28	346	7			5.00		16.98
29	Subtotal	31,276					
30							
31	Coyote Springs 2						
32	341	11,317			4.17		21.01
33	342	19,128			4.17		20.97
34	344	115,545			4.14		22.09
35	345	12,490			4.20		20.79
36	346	1,008			4.17		21.01
37	Subtotal	159,488					
38							
39	TRANSMISSION PLANT						
40	350	10,669			1.32		
41	352	14,506	50.00	-5.00	2.09	R4	37.70
42	353	163,771	50.00	-25.00	2.63	R4	33.58
43	354	17,075	75.00	-5.00	1.40	R4	48.36
44	355	114,009	45.00	-33.00	3.03	R3	28.31
45	356	87,390	55.00		1.80	R2	39.95
46	357	561	60.00	-2.00	1.66	R4	30.10
47	358	1,318	60.00		1.52	R4	30.97
48	359	1,827	75.00		1.34	R5	52.66
49	Subtotal	411,126					
50							

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	DISTRIBUTION PLANT						
13	361	10,552	50.00	-10.00	2.13	R3	30.73
14	362	80,273	40.00		2.47	R1.5	26.98
15	364	180,491	45.00	5.00	1.87	R1	31.29
16	365	118,579	50.00	20.00	1.30	R2	35.29
17	366	63,872	60.00	-10.00	1.88	R4	48.75
18	367	102,554	40.00	-17.00	2.27	L1	34.39
19	368	145,262	40.00	-10.00	2.65	R2	24.36
20	369	102,488	48.00	-10.00	2.13	R3	30.24
21	370	23,535	35.00	-10.00	3.28	R3	27.71
22	373	13,297	25.00	-10.00	2.21	R2	5.99
23	373.4	12,135	20.00	-10.00	6.05	R2	11.63
24	Subtotal	853,038					
25							
26	GENERAL PLANT						
27	390.1	2,097	50.00	-5.00	2.01	L0.5	19.32
28	391.1	325	6.00		20.27	S1	3.90
29	393	211	40.00	2.00	2.41	R3	30.77
30	394	3,141	20.00	10.00	4.49	L3	10.75
31	395	3,054	28.00		3.37	L1	8.59
32	397	30,285	12.00		9.82	L2	3.72
33	398	3	25.00		3.72	R2	14.36
34	Subtotal	39,116					
35							
36	MISC POWER						
37	392	1,428			4.93		
38	396	2,428			7.43		
39	Subtotal	3,856					
40							
41	TOTAL COMPANY	2,293,681					
42							
43							
44							
45							
46							
47							
48							
49							
50							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Federal Energy Regulatory Commission				
2	Charges include annual fee and license fees				
3	for the Spokane River Project, the Cabinet				
4	Gorge Project and the Noxon Rapids Project.	1,899,333	52,351	1,951,684	
5					
6					
7					
8					
9	Washington Utilities and Transportation				
10	Commission: includes annual fee and various				
11	other electric dockets	734,126	377,243	1,111,369	
12					
13	Includes annual fee and various other natural				
14	gas dockets	420,821	113,821	534,642	
15					
16	Idaho Public Utilities Commission				
17	Includes annual fee and various other electric				
18	dockets	479,736	100,842	580,578	
19					
20	Includes annual fee and various other natural				
21	gas dockets	215,534	44,431	259,965	
22					
23	Public Utility Commission of Oregon				
24	Includes annual fees and various other natural				
25	gas dockets	510,858	246,039	756,897	
26					
27	Not directly assigned electric		671,517	671,517	
28	Not directly assigned natural gas		244,080	244,080	
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	4,260,408	1,850,324	6,110,732	

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
							2
							3
Electric	928	1,951,684					4
							5
							6
							7
							8
							9
							10
Electric	928	1,111,369					11
							12
							13
Gas	928	534,642					14
							15
							16
							17
Electric	928	580,578					18
							19
							20
Gas	928	259,965					21
							22
							23
							24
Gas	928	756,897					25
							26
Electric	928	671,517					27
Gas	928	244,080					28
							29
							30
							31
							32
							33
							34
							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		6,110,732					46

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

DISTRIBUTION OF SALARIES AND WAGES

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

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	8,384,189		
4	Transmission	2,299,612		
5	Regional Market			
6	Distribution	3,747,749		
7	Customer Accounts	5,320,575		
8	Customer Service and Informational	313,074		
9	Sales	408,790		
10	Administrative and General	11,690,065		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	32,164,054		
12	Maintenance			
13	Production	2,469,898		
14	Transmission	822,530		
15	Regional Market			
16	Distribution	4,001,728		
17	Administrative and General			
18	TOTAL Maintenance (Total of lines 13 thru 17)	7,294,156		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	10,854,087		
21	Transmission (Enter Total of lines 4 and 14)	3,122,142		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	7,749,477		
24	Customer Accounts (Transcribe from line 7)	5,320,575		
25	Customer Service and Informational (Transcribe from line 8)	313,074		
26	Sales (Transcribe from line 9)	408,790		
27	Administrative and General (Enter Total of lines 10 and 17)	11,690,065		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	39,458,210	9,133,851	48,592,061
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply	624,361		
34	Storage, LNG Terminaling and Processing	13,142		
35	Transmission			
36	Distribution	3,890,896		
37	Customer Accounts	2,268,760		
38	Customer Service and Informational	121,993		
39	Sales	236,178		
40	Administrative and General	4,409,392		
41	TOTAL Operation (Enter Total of lines 31 thru 40)	11,564,722		
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission	468,112		

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution	2,357,283		
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)	2,825,395		
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)	624,361		
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru	13,142		
56	Transmission (Lines 35 and 47)	468,112		
57	Distribution (Lines 36 and 48)	6,248,179		
58	Customer Accounts (Line 37)	2,268,760		
59	Customer Service and Informational (Line 38)	121,993		
60	Sales (Line 39)	236,178		
61	Administrative and General (Lines 40 and 49)	4,409,392		
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)	14,390,117	3,339,490	17,729,607
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	53,848,327	12,473,341	66,321,668
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	23,484,306	5,452,535	28,936,841
69	Gas Plant	6,067,681	1,408,780	7,476,461
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	29,551,987	6,861,315	36,413,302
72	Plant Removal (By Utility Departments)			
73	Electric Plant	851,164	195,754	1,046,918
74	Gas Plant	128,585	29,572	158,157
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	979,749	225,326	1,205,075
77	Other Accounts (Specify, provide details in footnote):			
78	Stores Expense (163)	1,553,398	-1,553,398	
79				
80	Regulatory Asset (182)	474,224		474,224
81	Preliminary Survey and Investigation (183)	16,803		16,803
82	Small Tool Expense (184)	2,088,003	-2,088,003	
83	Misc Deferred Debits (186)	28,124,330		28,124,330
84				
85				
86	Non-operating Expenses (417)	565,364		565,364
87				
88	activities (426)	232,399		232,399
89	Employee Incentive Plan (232380)	5,943,452	-5,943,452	
90	DSM Tarrif Rider and Payroll Equilization Liability (242600,	14,610,923	-13,462,599	1,148,324
91	Incentive / Stock Compensation (283000)	18,822		18,822
92				
93				
94				
95	TOTAL Other Accounts	53,627,718	-23,047,452	30,580,266
96	TOTAL SALARIES AND WAGES	138,007,781	-3,487,470	134,520,311

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

1 & 2. Common Plant in service and accumulated provision for depreciation

Acct. No.	Description	
303	Intangible	18,699,417
389	Land and Land Rights	3,063,259
390	Structures and Improvements	37,713,609
391	Office Furniture and Equipment	25,860,844
392	Transportation Equipment	1,915,153
393	Stores Equipment	960,021
394	Tools, Shop & Garage Equipment	1,432,208
395	Laboratory Equipment	883,966
396	Power Operated Equipment	1,503,158
397	Communications Equipment	14,163,939
398	Miscellaneous Equipment	640,572
399	Asset Retirement Cost	351,680

	Total Common Plant	107,187,825
	Const. Work in Progress	6,034,594

	Total Utility Plant	113,222,418
	Acc. Prov. for Dep. & Amort.	30,296,744

	Net Utility Plant	82,925,674
		----------

3. Common Expenses allocated to Electric and Gas departments:

Acct. No.	Description	Allocation to Total	Allocated to Electric Dept	Gas Dept	Basis of Allocation
901	Cust acct/collect supervision	1,004,306	533,668	470,638	#of cust @ yr end
902	Meter reading expenses	3,176,370	1,972,812	1,203,558	#of cust @ yr end
903	Cust rec & collectn expenses	11,351,820	6,189,504	5,162,315	#of cust @ yr end
903.90-99	A/R misc fees	1,756,863	1,437,254	319,609	net direct plant
904	Uncollectible accounts	3,077,874	1,635,521	1,442,353	#of cust @ yr end
905	Misc cust acct expenses	357,706	190,079	167,628	#of cust @ yr end
907	Cust svce & Info exp supervision	0	0	0	# of cust @ yr end
908	Cust assistance expenses	798,084	495,675	302,409	#of cust @ yr end
909	Info & instruct advert expenses	8,127	4,561	3,566	#of cust @ yr end

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

910	Misc cust serv & info expenses	188,578	117,124	71,454	#of cust @ yr end
911	Sales expense -supervision	0	0	0	#of cust @ yr end
912	Demo and selling expenses	807,597	501,590	306,007	#of cust @ yr end
913	Advertising expenses	416,732	258,828	157,904	#of cust @ yr end
916	Misc sales expenses	304,805	189,312	115,494	#of cust @ yr end
920	Admin & gen salaries	24,754,441	18,207,376	6,547,066	four factor
921	Office supplies & expenses	4,755,584	3,489,430	1,266,154	four factor
922	Admin expenses tranf-credit	0	0	0	four factor
923	Outside services employed	15,663,513	11,487,934	4,175,579	four factor
924	Property insurance	1,236,433	906,825	329,608	four factor
925	Injuries and damages	5,278,992	3,985,542	1,293,450	four factor
926	Employee pensions&benefits	34,601,785	25,460,092	9,141,694	four factor
927	Franchise requirement	0	0	0	four factor
928	Regulatory commission expenses	915,597	671,517	244,080	four factor
929	Duplicate charges-credit	0	0	0	four factor
930.1	General advertising expenses	11,355	9,097	2,258	four factor
930.2	Misc general expenses	3,714,766	2,768,846	945,920	four factor
931	Rents	968,796	698,836	269,960	four factor
935	Maint of general plant	7,315,026	5,436,594	1,878,432	four factor
403	Depreciation	5,576,430	4,164,695	1,411,735	four factor
404	Amort of LTD term plant	3,289,934	2,412,904	877,030	four factor

Note 1: The 4 factor allocator is made up of 25% each -customer counts, direct labor, direct O&M & Net direct plant

4. Letters of approval received from staffs of State Regulatory Commissions in 1993

PURCHASES AND SALES OF ANCILLARY SERVICES

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

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

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch	601	MW	122,098			
2	Reactive Supply and Voltage	601	MW	35,365			
3	Regulation and Frequency Response	342,205	MWh	117,770	70,781	MW	632,779
4	Energy Imbalance				720	MW	2,003,871
5	Operating Reserve - Spinning				59,250	MWh	695,911
6	Operating Reserve - Supplement	58,645	MWh	980,605	145,376	MWh	1,722,829
7	Other	1,348,028	MW	12,051,374	1,348,028	MW	12,051,374
8	Total (Lines 1 thru 7)	1,750,080		13,307,212	1,624,155		17,106,764

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	2,035	12	800	1,621	375	268	42		56
2	February	1,795	1	1900	1,454	304	268	39	75	76
3	March	1,745	2	800	1,400	303	268	39	1	30
4	Total for Quarter 1	5,575			4,475	982	804	120	76	162
5	April	1,522	2	1000	1,263	219	268	41	240	181
6	May	1,505	31	1700	1,206	233	269	50	365	122
7	June	1,572	20	1700	1,286	228	271	52	280	175
8	Total for Quarter 2	4,599			3,755	680	808	143	885	478
9	July	1,906	13	1400	1,576	282	271	45	453	114
10	August	1,783	2	1700	1,464	258	270	46	264	53
11	September	1,503	4	1700	1,240	208	270	47	120	310
12	Total for Quarter 3	5,192			4,280	748	811	138	837	477
13	October	1,601	31	800	1,315	257	269	40	101	124
14	November	1,783	28	1800	1,465	293	146	34	105	
15	December	1,870	12	1800	1,529	310	158	34	130	49
16	Total for Quarter 4	5,254			4,309	860	573	108	336	173
17	Total Year to Date/Year	20,620			16,819	3,270	2,996	509	2,134	1,290

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY	
2	Generation (Excluding Station Use):	
3	Steam	1,972,174
4	Nuclear	
5	Hydro-Conventional	3,688,791
6	Hydro-Pumped Storage	
7	Other	1,668,093
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	7,329,058
10	Purchases	4,761,534
11	Power Exchanges:	
12	Received	974,470
13	Delivered	974,494
14	Net Exchanges (Line 12 minus line 13)	-24
15	Transmission For Other (Wheeling)	
16	Received	3,553,693
17	Delivered	3,553,693
18	Net Transmission for Other (Line 16 minus line 17)	
19	Transmission By Others Losses	
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	12,090,568

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	8,924,726
23	Requirements Sales for Resale (See instruction 4, page 311.)	
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	2,536,103
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	12,302
27	Total Energy Losses	617,437
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	12,090,568

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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MONTHLY PEAKS AND OUTPUT

(1) Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
(2) Report on line 2 by month the system's output in Megawatt hours for each month.
(3) Report on line 3 by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
(4) Report on line 4 by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
(5) Report on lines 5 and 6 the specified information for each monthly peak load reported on line 4.

NAME OF SYSTEM: Avista Corp

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	1,135,138	173,913	1,685	12	800
30	February	984,749	187,615	1,512	1	1900
31	March	1,072,376	295,568	1,452	2	800
32	April	1,048,984	327,921	1,301	2	1000
33	May	1,097,282	377,603	1,242	31	1700
34	June	1,039,192	332,215	1,318	20	1700
35	July	1,024,840	169,481	1,629	13	1400
36	August	918,583	131,028	1,519	2	1700
37	September	838,879	132,105	1,270	4	1700
38	October	872,747	114,257	1,361	31	800
39	November	959,467	134,000	1,529	28	1800
40	December	1,098,331	160,397	1,595	12	1800
41	TOTAL	12,090,568	2,536,103			

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Coyote Springs 2* (b)			Plant Name: *Spokane N.E.* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine			Gas Turbine		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Not Applicable			Not Applicable		
3	Year Originally Constructed	2003			1978		
4	Year Last Unit was Installed	2003			1978		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	287.00			61.80		
6	Net Peak Demand on Plant - MW (60 minutes)	306			57		
7	Plant Hours Connected to Load	6352			43		
8	Net Continuous Plant Capability (Megawatts)	279			61		
9	When Not Limited by Condenser Water	279			0		
10	When Limited by Condenser Water	279			0		
11	Average Number of Employees	22			1		
12	Net Generation, Exclusive of Plant Use - KWh	1622778000			2308000		
13	Cost of Plant: Land and Land Rights	0			129664		
14	Structures and Improvements	11339138			256733		
15	Equipment Costs	148179441			13225361		
16	Asset Retirement Costs	351682			0		
17	Total Cost	159870261			13611758		
18	Cost per KW of Installed Capacity (line 17/5) Including	557.0392			220.2550		
19	Production Expenses: Oper, Supv, & Engr	1019521			22822		
20	Fuel	95812681			238480		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	1082778			10459		
26	Misc Steam (or Nuclear) Power Expenses	22811			6872		
27	Rents	55601			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	882651			5421		
30	Maintenance of Structures	0			1301		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	1369934			86941		
33	Maintenance of Misc Steam (or Nuclear) Plant	-3588			20931		
34	Total Production Expenses	100242389			393227		
35	Expenses per Net KWh	0.0618			0.1704		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas			Gas		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF			MCF		
38	Quantity (Units) of Fuel Burned	11169074	0	0	29202	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1020000	0	0	1020000	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	8.578	0.000	0.000	8.167	0.000	0.000
41	Average Cost of Fuel per Unit Burned	8.578	0.000	0.000	8.167	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	8.410	0.000	0.000	8.006	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.059	0.000	0.000	0.103	0.000	0.000
44	Average BTU per KWh Net Generation	7020.000	0.000	0.000	12906.000	0.000	0.000

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Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Kettle Falls* (d)	Plant Name: *Colstrip* (e)	Plant Name: *Rathdrum* (f)	Line No.
Steam	Steam	Gas Turbine	1
Conventional	Conventional	Not Applicable	2
1983	1984	1995	3
1983	1985	1995	4
50.70	233.40	166.50	5
52	226	161	6
7105	8687	224	7
50	222	149	8
50	222	0	9
49	222	0	10
30	210	2	11
299413000	1672761000	18228000	12
941300	1291606	621682	13
24599040	99970611	3186951	14
66182019	185137373	55862104	15
1114206	134589	0	16
92836565	286534179	59670737	17
1831.0960	1227.6529	358.3828	18
130610	141110	14390	19
9889463	16829966	1774127	20
0	0	0	21
538724	1301489	0	22
0	0	0	23
0	0	0	24
793599	41532	131518	25
386169	1606237	251496	26
0	29922	0	27
0	0	0	28
76477	438221	21929	29
45617	451048	984	30
1166733	4557363	0	31
351380	679784	113087	32
181661	542111	102696	33
13560433	26618783	2410227	34
0.0453	0.0159	0.1322	35

(d)			(e)			(f)			Line No.
Wood	Gas		Coal	Oil		Gas			36
Tons	MCF		Tons	BBL		MCF			37
449183	4482	0	1057290	2651	0	227657	0	0	38
8500000	1020000	0	16856167	140000	0	1020000	0	0	39
21.933	8.412	0.000	15.626	116.335	0.000	7.793	0.000	0.000	40
21.933	8.412	0.000	15.626	116.335	0.000	7.793	0.000	0.000	41
2.580	8.247	0.000	0.930	19.640	0.000	7.640	0.000	0.000	42
0.033	0.098	0.000	0.010	0.000	0.000	0.097	0.000	0.000	43
12768.000	12753.000	0.000	10667.000	10667.000	0.000	12739.000	0.000	0.000	44

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Boulder Park* (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Internal Comb					
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional					
3	Year Originally Constructed	2002					
4	Year Last Unit was Installed	2002					
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	24.60			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	25			0		
7	Plant Hours Connected to Load	1169			0		
8	Net Continuous Plant Capability (Megawatts)	25			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	1			0		
12	Net Generation, Exclusive of Plant Use - KWh	23313000			0		
13	Cost of Plant: Land and Land Rights	144733			0		
14	Structures and Improvements	724602			0		
15	Equipment Costs	30567830			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	31437165			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	1277.9335			0.0000		
19	Production Expenses: Oper, Supv, & Engr	10523			0		
20	Fuel	1810757			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	56407			0		
26	Misc Steam (or Nuclear) Power Expenses	8529			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	8912			0		
30	Maintenance of Structures	445			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	157316			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	38146			0		
34	Total Production Expenses	2091035			0		
35	Expenses per Net KWh	0.0897			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas					
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF					
38	Quantity (Units) of Fuel Burned	221152	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1020000	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	8.188	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	8.188	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	8.027	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.078	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	9676.000	0.000	0.000	0.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0.0000	0.0000	0.0000	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 2545 Plant Name: Monroe Street (b)	FERC Licensed Project No. 2545 Plant Name: Upper Falls (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Run-of-River
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1890	1922
4	Year Last Unit was Installed	1992	1922
5	Total installed cap (Gen name plate Rating in MW)	14.80	10.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	16	11
7	Plant Hours Connect to Load	8,678	8,676
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	16	11
10	(b) Under the Most Adverse Oper Conditions	14	10
11	Average Number of Employees	1	1
12	Net Generation, Exclusive of Plant Use - Kwh	100,338,000	62,668,000
13	Cost of Plant		
14	Land and Land Rights	0	1,081,854
15	Structures and Improvements	8,405,476	491,800
16	Reservoirs, Dams, and Waterways	8,045,079	7,126,169
17	Equipment Costs	12,704,055	2,019,286
18	Roads, Railroads, and Bridges	50,448	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	29,205,058	10,719,109
21	Cost per KW of Installed Capacity (line 20 / 5)	1,973.3147	1,071.9109
22	Production Expenses		
23	Operation Supervision and Engineering	34,910	34,898
24	Water for Power	0	0
25	Hydraulic Expenses	2,470	4,911
26	Electric Expenses	415,902	414,734
27	Misc Hydraulic Power Generation Expenses	22,846	46,745
28	Rents	0	0
29	Maintenance Supervision and Engineering	996	747
30	Maintenance of Structures	24	14,219
31	Maintenance of Reservoirs, Dams, and Waterways	19,385	37,751
32	Maintenance of Electric Plant	33,034	45,408
33	Maintenance of Misc Hydraulic Plant	2,301	649
34	Total Production Expenses (total 23 thru 33)	531,868	600,062
35	Expenses per net KWh	0.0053	0.0096

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 2058 Plant Name: Cabinet Gorge (d)	FERC Licensed Project No. 2058 Plant Name: Noxon Rapids (e)	FERC Licensed Project No. 2545 Plant Name: Long Lake (f)	Line No.
Storage	Storage	Storage	1
Outdoor	Outdoor	Conventional	2
1952	1959	1915	3
1953	1977	1924	4
265.20	473.40	70.00	5
261	445	90	6
8,760	7,017	6,487	7
			8
261	445	90	9
177	263	87	10
12	13	5	11
1,088,206,000	1,590,451,000	471,412,000	12
			13
10,270,526	35,615,263	1,597,959	14
10,078,381	12,866,941	1,713,681	15
25,577,279	31,859,561	16,638,010	16
44,956,724	56,195,687	12,042,252	17
1,098,564	225,369	0	18
0	0	0	19
91,981,474	136,762,821	31,991,902	20
346.8381	288.8948	457.0272	21
			22
292,550	86,126	-326	23
0	0	0	24
6,594	71,796	7,005	25
822,868	927,900	518,083	26
248,038	147,929	62,124	27
0	0	0	28
22,425	64,791	48,987	29
70,873	147,358	36,593	30
183,200	46,805	15,402	31
581,733	810,852	117,448	32
6,430	39,805	6,976	33
2,234,711	2,343,362	812,292	34
0.0021	0.0015	0.0017	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 2545 Plant Name: NIne Mile Falls (b)	FERC Licensed Project No. 2545 Plant Name: Post Falls (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1908	1906
4	Year Last Unit was Installed	1994	1980
5	Total installed cap (Gen name plate Rating in MW)	26.40	14.75
6	Net Peak Demand on Plant-Megawatts (60 minutes)	20	18
7	Plant Hours Connect to Load	8,746	8,708
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	20	18
10	(b) Under the Most Adverse Oper Conditions	16	15
11	Average Number of Employees	1	2
12	Net Generation, Exclusive of Plant Use - Kwh	99,421,000	83,374,000
13	Cost of Plant		
14	Land and Land Rights	33,429	3,076,554
15	Structures and Improvements	3,943,110	972,032
16	Reservoirs, Dams, and Waterways	11,840,543	6,044,594
17	Equipment Costs	12,391,557	3,311,936
18	Roads, Railroads, and Bridges	625,181	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	28,833,820	13,405,116
21	Cost per KW of Installed Capacity (line 20 / 5)	1,092.1902	908.8214
22	Production Expenses		
23	Operation Supervision and Engineering	74,062	34,737
24	Water for Power	0	0
25	Hydraulic Expenses	213	9,256
26	Electric Expenses	469,301	467,193
27	Misc Hydraulic Power Generation Expenses	41,919	39,515
28	Rents	0	0
29	Maintenance Supervision and Engineering	7,447	389
30	Maintenance of Structures	374	30,277
31	Maintenance of Reservoirs, Dams, and Waterways	121,900	268,583
32	Maintenance of Electric Plant	164,202	55,075
33	Maintenance of Misc Hydraulic Plant	748	4,981
34	Total Production Expenses (total 23 thru 33)	880,166	910,006
35	Expenses per net KWh	0.0089	0.0109

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: Little Falls (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
Run-of-River			1
Conventional			2
1910			3
1911			4
32.00	0.00	0.00	5
37	0	0	6
6,556	0	0	7
			8
37	0	0	9
35	0	0	10
5	0	0	11
192,921,000	0	0	12
			13
4,325,371	0	0	14
919,660	0	0	15
5,025,360	0	0	16
6,086,206	0	0	17
0	0	0	18
0	0	0	19
16,356,597	0	0	20
511.1437	0.0000	0.0000	21
			22
-505	0	0	23
0	0	0	24
6,991	0	0	25
453,391	0	0	26
36,463	0	0	27
685,876	0	0	28
17,517	0	0	29
27,632	0	0	30
568,707	0	0	31
132,055	0	0	32
5,648	0	0	33
1,933,775	0	0	34
0.0100	0.0000	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Kettle Falls CT	2002	7.20	8.0	1,466,000	9,169,338
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Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
1,273,519	60,148	139,844	33,211	Nat Gas	801	1
						2
						3
						4
						5
						6
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						46

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Group Sum		60.00	60.00		1.00		
2								
3	Group Sum		115.00	115.00		1,541.00		
4								
5	Beacon Sub #4	BPA Bell Sub	230.00	230.00	Steel Tower	1.00		1
6	Beacon Sub	BPA Bell Sub	230.00	230.00	H Type	5.00		1
7	Beacon Sub #5	BPA Bell Sub	230.00	230.00	Steel Pole	4.00		1
8	Beacon Sub #5	BPA Bell Sub	230.00	230.00	H Type	2.00		1
9	Beacon	Cabinet Gorge Plant	230.00	230.00	Steel Tower		1.00	1
10	Beacon	Cabinet Gorge Plant	230.00	230.00	Steel Pole	25.00		2
11	Beacon	Cabinet Gorge Plant	230.00	230.00	H Type	52.00		1
12	Beacon Sub	Lolo Sub	230.00	230.00	Steel Tower	1.00		1
13	Beacon Sub	Lolo Sub	230.00	230.00	H Type	108.00		1
14	Benewah	Shawnee	230.00	230.00	Steel Pole	15.00		1
15	Noxon Plant	Pine Creek Sub	230.00	230.00	H Type	43.00		1
16	Cabinet Gorge Plant	Noxon	230.00	230.00	H Type	19.00		1
17	Benewah Sw. Station	Pine Creek Sub	230.00	230.00	Steel Tower			1
18	Benewah Sw. Station	Pine Creek Sub	230.00	230.00	H Type	43.00		1
19	Divide Creek	Lolo Sub	230.00	230.00	Steel Tower			1
20	Divide Creek	Lolo Sub	230.00	230.00	H Type	43.00		1
21	N. Lewiston	Walla Walla	230.00	230.00	Steel Tower	4.00		1
22	N. Lewiston	Walla Walla	230.00	230.00	H Type	32.00		1
23	N. Lewiston	Shawnee	230.00	230.00	Steel Tower	7.00		1
24	N. Lewiston	Shawnee	230.00	230.00	H Type	27.00		1
25	Walla Walla	Wanapum	230.00	230.00	Alum.			1
26	Walla Walla	Wanapum	230.00	230.00	H Type	78.00		1
27	BPA (Libby)	Noxon Plant	230.00	230.00	Steel Tower	1.00		1
28	BPA/Hot Springs #1	Noxon Plant	230.00	230.00	Steel Tower	1.00		1
29	BPA/Hot Springs #2	Noxon Plant (dead)	230.00	230.00	Steel Tower		2.00	1
30	BPA/Hot Springs #2	Noxon Plant	230.00	230.00	H Type	68.00		1
31	BPA Line	West Side Sub	230.00	230.00	Steel Pole	2.00		2
32	Hatwai	N. Lewiston Sub	230.00	230.00	H Type	7.00		1
33	Divide Creek	Imnaha	230.00	230.00	H Type	20.00		1
34	Colstrip Plant	Broadview	500.00	500.00				
35								
36					TOTAL	2,150.00	3.00	31

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
	136,038	70,092	206,130					1
								2
	6,631,146	81,423,442	88,054,588	166,843	608,832		775,675	3
								4
795 McMACSR	17,913	1,334,573	1,352,486					5
1272 McMACSR								6
1272 ACSS								7
1272 ACSS	30,323	3,226,063	3,256,386					8
795 McMACSR								9
1590 ACSS								10
795 McMACSR	324,327	36,008,024	36,332,351		10,898		10,898	11
795 McMACSR								12
1272 McMAL	456,162	6,713,900	7,170,062	220	15,122		15,342	13
1590 ACSS	569,739	46,617,039	47,186,778		1,478		1,478	14
954 McMAL	105,647	17,177,270	17,282,917	6,575	39,862		46,437	15
954 McMAL	49,049	1,066,610	1,115,659		3,882		3,882	16
954 McMAL								17
954 McMAL	157,193	2,598,576	2,755,769	1,545	19,089		20,634	18
1272 McMAL								19
1272 McMAL	86,228	3,656,083	3,742,311	12,549	13,971		26,520	20
1272 McMAL								21
1272 McMAL	623,984	6,044,932	6,668,916	1,800	10,343		12,143	22
1272 McMAL								23
1272 McMAL	872,151	7,570,610	8,442,761	8,846	12,178		21,024	24
1272 McMAL								25
1272 McMAL	70,781	2,461,474	2,532,255	1,993	4,847		6,840	26
1272 McMAL								27
1272 McMAL		19,521	19,521	509	925		1,434	28
1272 McMAL								29
1272 McMAL	144,638	3,287,453	3,432,091	3,257	125,954		129,211	30
1272 McMAL	36,461	587,224	623,685					31
1272 McMACSR	106,581	2,517,780	2,624,361	910	32,232		33,142	32
1272 McMAL	60,302	1,297,448	1,357,750					33
	595,789	28,545,289	29,141,078	89,878	301,195	68,268	459,341	34
								35
	11,074,452	252,223,403	263,297,855	294,925	1,200,808	68,268	1,564,001	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.

2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	Benewah	Shawnee	15.00	Steel Pole	8.00	1	1
2	Beacon Sub #5	BPA Bell Sub	4.00	Steel Pole	8.00	1	1
3	Beacon Sub #5	BPA Bell Sub	2.00	H Type	8.00	1	1
4							
5							
6							
7							
8							
9							
10							
11							
12							
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40							
41							
42							
43							
44	TOTAL		21.00		24.00	3	3

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage KV (Operating) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
1590	ACSS	SDC-20.79	230	569,739	22,160,531	24,456,508		47,186,778	1
1272	ACSS	SP-20.79	230						2
1272	ACSS	H-24.25	230		1,323,365	1,503,370		2,826,735	3
									4
									5
									6
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				569,739	23,483,896	25,959,878		50,013,513	44

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	STATE OF WASHINGTON				
2					
3	Airway Heights	Distr. Unattended	115.00	13.80	
4	Barker Road	Distr. Unattended	110.00	13.80	
5	Beacon	Trnsm. Unattended	230.00	115.00	13.80
6	Boulder	Trnsm. Unattended	230.00	115.00	13.80
7	Chester	Distr. Unattended	115.00	13.80	
8	Chewelah 115Kv	Distr. Unattended	115.00	13.80	
9	Colbert	Distr. Unattended	115.00	13.80	
10	College & Walnut	Distr. Unattended	115.00	13.80	
11	Colville 115Kv	Distr. Unattended	115.00	13.80	
12	Dry Creek	Trnsm. Unattended	230.00	115.00	13.80
13	Dry Gulch	Distr. Unattended	115.00	13.80	
14	East Colfax	Distr. Unattended	115.00	13.80	
15	East Farms	Distr. Unattended	115.00	13.80	
16	Fort Wright	Distr. Unattended	115.00	13.80	
17	Francis and Cedar	Distr. Unattended	115.00	13.80	
18	Gifford	Distr. Unattended	115.00	34.00	
19	Glenrose	Distr. Unattended	115.00	13.80	
20	Greenwood	Distr. Unattended	115.00	13.80	
21	Hallett & White 115-13kv	Distr. Unattended	115.00	13.80	
22	Industrial Park	Distr. Unattended	115.00	13.80	
23	Kettle Falls	Distr. Unattended	115.00	13.80	
24	Lee & Reynolds	Distr. Unattended	115.00	13.80	
25	Liberty Lake	Distr. Unattended	115.00	13.80	
26	Little Falls 115/34Kv	Distr. Unattended	115.00	34.00	
27	Lyons & Standard	Distr. Unattended	115.00	13.80	
28	Mead	Distr. Unattended	115.00	13.80	
29	Metro	Distr. Unattended	115.00	13.80	
30	Milan	Distr. Unattended	115.00	13.80	
31	Millwood	Trnsm & Dist Unattd	115.00	60.00	13.80
32	Ninth & Central	Distr. Unattended	115.00	13.80	
33	Northeast	Distr. Unattended	115.00	13.80	
34	Northwest	Distr. Unattended	115.00	13.80	
35	Opportunity	Dist. Unattended	115.00	13.80	
36	Othello	Distr. Unattended	115.00	13.80	
37	Post Street	Distr. Unattended	115.00	13.80	
38	Pound Lane	Distr. Unattended	115.00	13.80	
39	Pullman	Dist Unattended	115.00	13.80	
40	Ross Park	Distr. Unattended	115.00	13.80	

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
						2
24	2		Frcd Oil & Air Fan	2	40	3
12	1		Two Stage Fan	1	20	4
536	4		Frcd Oil & Air Fan	4	560	5
300	2		Two Stage Fan	2	500	6
24	2		Frcd Oil & Air Fan	2	40	7
15	3		Frcd Air	3	15	8
12	1		Frcd Oil & Air Fan	1	20	9
36	2		Two Stage Fan	2	60	10
31	3		Frcd Oil & Air Fan	3	45	11
150	1		Two Stage Fan	1	250	12
24	2		Frcd Oil & Air Fan	2	40	13
12	1		FrOil/Air Fan	1	20	14
12	1		Two Stage Fan	1	20	15
24	2		Fr Oil/Air/2StgFan	2	40	16
60	2		Frcd Air Fan	2	36	17
12	1					18
12	1		Frcd Oil & Air Fan	1	20	19
13	4	1	FrOil/Air/Two Stage	4	22	20
12	1		Two Stg Fan	1	20	21
28	3		Two Stg/Pt/Frcd Oil	40	40	22
12	1		Frcd Oil & Air Fan	1	20	23
12	1		Two Stage Fan	1	20	24
24	2		Two Stage Fan	2	40	25
12	1					26
36	2		Two Stage Fan	2	60	27
18	1		Two Stage Fan	1	30	28
24	2		Two Stage Fan	2	40	29
24	2		Frcd Oil & Air Fan	2	40	30
44	3	1	FrcAir/FrcOil/AirFan	3	61	31
24	2	1	Frcd & Two Stage Fan	2	40	32
24	2		Two Stage Fan	2	40	33
24	2		Two Stage Fan	2	40	34
12	1		Two Stage Fan	1	20	35
24	2		FrOil/AirFan	2	40	36
95	4		Frcd Oil & Wt Fan	4	95	37
24	2		Two Stage Fan	2	40	38
24	2		Frcd Oil & Air Fan	2	40	39
30	2		Two Stage Fan	2	60	40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Roxboro	Distr. Unattended	115.00	24.00	
2	Shawnee	Trans. Unattended	230.00	115.00	
3	Silver Lake	Distr. Unattended	115.00	13.80	
4	Southeast	Distr. Unattended	115.00	13.80	
5	South Othello	Distr. Unattended	115.00	13.80	
6	South Pullman	Distr. Unattended	115.00	13.80	
7	Sunset	Distr. Unattended	115.00	13.80	
8	Third & Hatch	Distr. Unattended	115.00	13.80	
9	Waikiki	Distr. Unattended	115.00	13.80	
10	West Side	Trans. Unattended	230.00	115.00	13.80
11	Other: 72substa less than 10MVA	Distr. Unattended			
12					
13	STATE OF IDAHO				
14	Appleway	Dist & Trfr Unattnd	115.00	13.80	
15	Avondale	Dist. Unattended	115.00	13.80	
16	Benewah	Trans. Unattended	230.00	115.00	13.80
17	Big Creek	Distr. Unattended	115.00	13.80	
18	Blue Creek	Distr. Unattended	115.00	13.80	
19	Bunker Hill	Distr. Unattended	115.00	13.80	
20	Clark Fork	Distr. Unattended	115.00	21.80	
21	Coeur d'Alene 15th Ave	Distr. Unattended	115.00	13.80	
22	Cottonwood	Distr. Unattended	115.00	24.90	
23	Dalton	Distr. Unattended	115.00	13.80	
24	Grangeville	Dist & Trfr Unattnd	115.00	13.80	
25	Holbrook	Distr. Unattended	115.00	13.80	
26	Huetter	Distr. Unattended	115.00	13.80	
27	Juliaetta	Distr. Unattended	115.00	13.80	
28	Kamiah	Dist & Trfr Unattnd	115.00	13.80	
29	Kooskia	Distr. Unattended	115.00	13.80	
30	Lolo	Tran & Dist Unattnd	230.00	115.00	13.80
31	Moscow	Distr. Unattended	115.00	13.80	
32	Moscow 230Kv	Tran & Dist Unattnd	230.00	115.00	13.80
33	North Moscow	Distr. Unattended	115.00	13.80	
34	North Lewiston	Trans Unattended	230.00	115.00	13.80
35	North Lewiston	Distr. Unattended	115.00	13.80	
36	Oden	Distr. Unattended	115.00	21.80	
37	Oldtown	Distr. Unattended	115.00	21.80	
38	Orofino	Distr. Unattended	115.00	13.80	
39	Osburn	Distr. Unattended	115.00	13.80	
40	Pine Creek	Tran & Dist Unattnd	230.00	110.00	13.80

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
24	2		Two Stage Fan	2	40	1
250	1					2
12	1		Frcd Oil & Air Fan	1	20	3
30	2		Two Stage Fan	2	50	4
12	1		Two Stage Fan	1	20	5
30	2		Two Stage Fan	240	50	6
35	4	1	Pt. & Two Stage Fan	4	50	7
54	3		Two Stg Fan & Cap	103	90	8
24	2		Two Stage Fan	2	40	9
250	2					10
193	137					11
						12
						13
30	2		Two Stage Fan	2	50	14
12	1		Frcd Oil & Air Fan	1	20	15
125	1					16
17	2		Portable Fan	2	22	17
20	3	1				18
12	1		Frcd Air Fan	1	26	19
10	1		Frcd Air Fan	1	13	20
36	2		Two Stage Fan	2	60	21
12	1		Two Stage Fan	1	20	22
24	2		FrcOil/Air2StgFan	2	40	23
25	4		FrcdOil/Air/Pt Fan	2	34	24
12	1		Two Stage Fan	1	20	25
12	1		Two Stage Fan	1	20	26
12	1		Frcd Oil & Air Fan	1	20	27
12	1		Two Stage Fan	1	20	28
15	3		Frcd Air Fan	2	20	29
270	3		Frcd Oil/Air/Two Stg	1	262	30
24	2		FrOil/Air/2Stg Fan	2	40	31
137	2	1	Capacitors	80	182	32
12	1		Two Stage Fan	1	20	33
250	1	1	Frcd Oil/Air&Cptrs	81	295	34
10	3					35
10	1		Frcd Air Fan		13	36
10	1		Frcd Air Fan	1	13	37
20	2		Frcd Oil & Air Fan	1	28	38
12	1		Portable Fan	1	15	39
262	3		Capacitors	80	307	40

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Pleasant View	Distr. Unattended	115.00	13.80	
2	Post Falls	Distr. Unattended	115.00	13.80	
3	Potlatch	Dist & Trfr Unattnd	115.00	13.80	
4	Prarie	Distr. Unattended	115.00	13.80	
5	Priest River	Distr. Unattended	115.00	20.80	
6	Sagle	Dist. Unattended	115.00	20.80	
7	Sandpoint	Distr. Unattended	115.00	20.80	
8	South Lewiston	Distr. Unattended	115.00	13.80	
9	Sweetwater	Distr. Unattended	115.00	24.00	
10	St. Maries	Distr. Unattended	115.00	24.00	
11	Tenth & Stewart	Distr. Unattended	115.00	13.80	
12	Wallace	Dist & Whse Unattnd	115.00	13.80	
13	Rathdrum	Tran & Dist Unattnd	230.00	115.00	13.80
14	Other: 30 substa less than 10 MVA	Distr. Unattended			
15					
16	STATE OF MONTANA				
17	1 substation less than 10 MVA	Distr. Unattended			
18					
19	SUBSTA. @ GENERATING PLANTS				
20	STATE OF WASHINGTON				
21	Boulder Park	Trans Step-Up	115.00	13.80	
22	Kettle Falls	Trans Step-Up	115.00	13.80	
23	Long Lake	Trans.	115.00	4.00	4.00
24	Nine Mile	Trns Step-Up & Dist	115.00	60.00	2.30
25	Little Falls	Trans.	115.00	4.00	
26	Northeast	Trans. Step-Up	115.00	13.80	
27					
28	STATE OF IDAHO				
29	Cabinet Gorge (Switchyard)		230.00	115.00	13.80
30	Cabinet Gorge (HED)	Trans. Step-Up	230.00	13.80	
31	Post Falls	Trans. Step-Up	115.00	2.30	
32	Rathdrum	Trans. Step-Up	115.00	13.80	
33	STATE OF MONTANA				
34	Noxon	Trans. Step-Up	230.00	13.80	
35					
36	STATE OF OREGON				
37	Coyote Springs II	Trans. Step -Up	500.00	13.80	18.00
38					
39	SUMMARY:				
40	Washington:				

Name of Respondent Avista Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report End of 2007/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
12	1		Two Stage Fan	1	20	1
18	1		Two Stage Fan	1	30	2
15	2		Portable Fan	2	19	3
12	1		Frcd Oil & Air Fan	1	20	4
10	1	1	Frcd Air Fan	1	13	5
12	1		Two Stage Fan	1	20	6
30	3		Frcd Air Fan	3	38	7
27	4		Port Fan/FrcdOil/Air	4	39	8
12	1		Frcd Oil & Air Fan	1	20	9
24	2		Two Stage Fan	2	40	10
30	2		Frcd Oil/Air/Two Stg	2	50	11
10	3					12
462	3		FrcdOil/AirFan/Cptrs	243	470	13
86	48	1				14
						15
						16
5	1					17
						18
						19
						20
36	1		Two Stage Fan	1	60	21
30	1	1	Two Stage Fan	1	62	22
80	4	1				23
18	2		Frcd Oil & Air Fan	1	40	24
24	2		Frcd Oil & Air Fan	2	40	25
36	1		Two Stage Fan	1	60	26
						27
						28
125	1		2 stage fan	1	13	29
30	6	1	Frcd Oil and Air Fan	2	30	30
16	2		Frcd Air/Oil/Air Fan	2	21	31
114	2	3	Two Stage Fan	2	190	32
						33
532	9	1	Frcd Oil Air	6	555	34
						35
						36
213	1	1	Two Stage fan	2	355	37
						38
						39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	10 subs	Trans. Unattended			
2	113 subs	Distr. Unattended			
3	3 subs	Tran & Dist Unattnd			
4	Idaho:				
5	6 subs	Trans. Unattended			
6	59 subs	Distr. Unattended			
7	9 subs	Tran & Dist Unattnd			
8	Montana: 1 sub	Trans. Unattended			
9	1 sub	Distr. Unattended			
10	Oregon: 1 sub	Trans. Unattended			
11	System: 203 subs				
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	04/17/2008	End of 2007/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Number of Units (j)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Total Capacity (In MVa) (k)	Line No.
1189						1
1182						2
604						3
						4
660						5
565						6
1222						7
533						8
5						9
213						10
6173						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
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						22
						23
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						39
						40

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) X An Original (2) _ A Resubmission	04/17/2008	2007/Q4

FOOTNOTE DATA

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

1. Includes: Accum provision of non-recoverable plant of <$291,927>
FAS 143 depreciation of $30,791 less reversal of $92,858

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

Includes: Change in Removal Work in Progress - <$879,399>

Schedule Page: 224 Line No.: 3 Column: e

Line 3 - Avista Capital - Equity in Earnings Consists of:

($4,595,749)	Avista Capital YTD Net Income
$ 234,769	Subsidiary (Avista Advantage) Equity Compensation booked to #123120
($4,360,980)	Line 3 - Avista Capital - Equity in Earnings

Schedule Page: 224 Line No.: 5 Column: f

Line 5 - Avista Capital - Other Changes in Net Investment:

Represents the liability to non-controlling interest at Advantage IQ

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

Line 6 - Avista Capital - Other Changes in Net Investment:

Represents the change in controlling ownership of Advantage IQ

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

(1) Electric
(2) Natural gas and miscellaneous

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

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

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

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

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

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

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

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

Schedule Page: 227 Line No.: 10 Column: d

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

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

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

Schedule Page: 231 Line No.: 2 Column: b

Total Charges Incurred Life to Date.

Schedule Page: 231 Line No.: 2 Column: d

Centennial withdrew their request in the fourth quarter of 2007. Deposit plus interest less charges were reimbursed in fourth quarter 2007.

Schedule Page: 231 Line No.: 3 Column: b

Total Charges Incurred Life to Date.

Schedule Page: 231 Line No.: 3 Column: d

No reimbursements Received Life to Date.

Schedule Page: 231 Line No.: 22 Column: b

Total Charges Incurred Life to Date.

Schedule Page: 231 Line No.: 22 Column: d

Refunded RES America their Feasibility Study Deposit, due to completion, plus interest less charges during fourth quarter 2007.

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

Total Charges Incurred Life to Date.

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

No Reimbursements Received Life to Date.

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

Total Charges Incurred Life to Date.

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

No Reimbursements Received Life to Date.

Schedule Page: 250 Line No.: 4 Column: i

Restricted Shares

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

	2007	2006
Unvested shares at beginning of year	36,180	-
Shares granted	31,860	36,260
Shares cancelled	(19,936)	(80)
Shares vested	(19,967)	-
Unvested shares at end of year	28,137	36,180
Weighted average fair value at grant date	$25.60	$21.32
Unrecognized compensation expense at end of year (in thousands)	$733	$439
Intrinsic value, unvested shares at end of year (in thousands)	$606	$916
Intrinsic value, shares vested during the year (in thousands)	$461	$ -

Schedule Page: 250 Line No.: 4 Column: j

Restricted Shares

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

	2007	2006
Unvested shares at beginning of year	36,180	-
Shares granted	31,860	36,260
Shares cancelled	(19,936)	(80)
Shares vested	(19,967)	-
Unvested shares at end of year	28,137	36,180
Weighted average fair value at grant date	$25.60	$21.32
Unrecognized compensation expense at end of year (in thousands)	$733	$439
Intrinsic value, unvested shares at end of year (in thousands)	$606	$916
Intrinsic value, shares vested during the year (in thousands)	$461	$ -

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

Capital Stock Expense

The issuance costs increased by $1.5 million in new issuance cost from the December 2006 issuance of 3.2 million shares of common stock. A reduction of $0.7 million due to stock based compensation expense due to FASB 123(r). A $2.5 million reduction due to performance shares payout and withholding. The final reduction of $1.3 million was due to the maturity of Series K preferred stock and the re-classing of the issuance costs to retained earnings.

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

	2007	2006
Common Stock Issuance Costs	12,952,041	10,246,442
Tax Benefit on Options Exercised	(3,845,768)	(2,069,227)
Compensation Incentive accrual	(5,811,357)	(3,092,121)
Preferred Stock Issuance Costs, Series K	-	1,334,005
Year-end Balances	3,294,916	6,419,099

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

Footnote Linked. See note on 254, Row: 1, col/item:

Schedule Page: 256 Line No.: 24 Column: h

Accounts 223 and 224 net changes during 2007

Advances from associated companies was reduced by $600,000. The sale of Avista Energy was the reason for the reduction.

The $26,250,000 Series K preferred stock matured September 15, 2007

The $12,000,000 of medium term notes matured in January 2007.

The following table summarizes accounts 223 and 224 net activity for the years ended December 31:

	2007	2006
Advances from associated companies	1,200,000	1,800,000
Series K Preferred Stock	0	26,250,000
Medium term notes	0	12,000,000
Year-end Balances	1,200,000	40,050,000

Schedule Page: 256 Line No.: 29 Column: h

Accounts 223 and 224 net changes during 2007

Advances from associated companies was reduced by $600,000. The sale of Avista Energy was the reason for the reduction.

The $26,250,000 Series K preferred stock matured September 15, 2007

The $12,000,000 of medium term notes matured in January 2007.

The following table summarizes accounts 223 and 224 net activity for the years ended December 31:

	2007	2006
Advances from associated companies	1,200,000	1,800,000
Series K Preferred Stock	0	26,250,000
Medium term notes	0	12,000,000
Year-end Balances	1,200,000	40,050,000

Schedule Page: 256 Line No.: 32 Column: h

Accounts 223 and 224 net changes during 2007

Advances from associated companies was reduced by $600,000. The sale of Avista Energy was the reason for the reduction.

The $26,250,000 Series K preferred stock matured September 15, 2007

The $12,000,000 of medium term notes matured in January 2007.

The following table summarizes accounts 223 and 224 net activity for the years ended December 31:

	2007	2006
Advances from associated companies	1,200,000	1,800,000
Series K Preferred Stock	0	26,250,000
Medium term notes	0	12,000,000
Year-end Balances	1,200,000	40,050,000

Name of Respondent Avista Corporation	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/17/2008	Year/Period of Report 2007/Q4

FOOTNOTE DATA

Schedule Page: 261 Line No.: 5 Column: b

Taxable Income Not Reported on Books

Tax NOT Book Income	BPA C&RD Receipts	(108,870)
Tax NOT Book Income	Contributions in Aid of Construction - Electric	5,611,994
Tax NOT Book Income	CSS Temp Service Fees - ID	72,630
Tax NOT Book Income	CSS Temp Service Fees - WA	110,970
Tax NOT Book Income	Customer Uncollectibles - Sales for Resale - ED AN	(26,662)
Tax NOT Book Income	Contributions In Aid of Construction - Gas North	311,324
Tax NOT Book Income	BETC - Oregon Purchased Tax Credits (@ 87%)	(155,683)
Tax NOT Book Income	Contributions in Aid of Construction - OR	12,033
Tax NOT Book Income	*Customer Uncollectibles - OR*	-
Tax NOT Book Income	Customer Uncollectibles (excluding ED AN)	192,146
Tax NOT Book Income	Customer Uncollectibles (excluding ED AN)	48,294
Tax NOT Book Income	Customer Uncollectibles (excluding ED AN)	21,546
Tax NOT Book Income	BETC Interest / Discount Perm Diff	(50,153)
Tax NOT Book Income Total		**6,039,568**

Schedule Page: 261 Line No.: 10 Column: b

Deductions Recorded on Books Not Deducted for Return

FERC Pg. 261 Detail	**2007**	YTD
Book NOT Tax Expense	Book Depreciation - Electric	67,852,899
Book NOT Tax Expense	Book Depreciation - Electric	-
Book NOT Tax Expense	DSM - Old Electric Program Amort	1,280,293
Book NOT Tax Expense	FAS 106 - Deferred Amort Postretire Benefits - ED ID	88,782
Book NOT Tax Expense	FAS 106 - Deferred Amort Postretire Benefits - ED WA	250,574
Book NOT Tax Expense	Montana Settlement - ED ID	(1,366,800)
Book NOT Tax Expense	Montana Settlement - ED WA	(2,633,200)
Book NOT Tax Expense	Non-monetary Purchased Power	241,209
Book NOT Tax Expense	Rathdrum Turbine Sales Tax Refund	(33,828)
Book NOT Tax Expense	Redemption Expense Amort - PCBs	194,949
Book NOT Tax Expense	WNP3 - Investment Exchange Power	2,450,031
Book NOT Tax Expense	Book Depreciation - Gas North	10,898,141
Book NOT Tax Expense	Book Depreciation - Gas North	-
Book NOT Tax Expense	DSM - Old Gas Program Amort	437,557
Book NOT Tax Expense	FAS 106 - Deferred Amort Postretire Benefits - GD WA	55,561
Book NOT Tax Expense	Book Depreciation - Gas South	7,438,934
Book NOT Tax Expense	Book Depreciation - Gas South	-
Book NOT Tax Expense	Transportation Book Depreciation	122,167
Book NOT Tax Expense	Airplane Lease Payments	209,655
Book NOT Tax Expense	FAS106 (68.6% O&M)	(940,455)
Book NOT Tax Expense	Meal Disallowances	223,560
Book NOT Tax Expense	Paid Time Off Equalization	240,005
Book NOT Tax Expense	Redemption Expense Amort	5,652,715
Book NOT Tax Expense	Transportation Book Depreciation	1,092,226
Book NOT Tax Expense	Airplane Lease Payments	52,695
Book NOT Tax Expense	FAS106 (68.6% O&M)	(236,377)
Book NOT Tax Expense	Meal Disallowances	56,190
Book NOT Tax Expense	Paid Time Off Equalization	60,324
Book NOT Tax Expense	Redemption Expense Amort	1,420,770
Book NOT Tax Expense	Transportation Book Depreciation	271,097
Book NOT Tax Expense	Airplane Lease Payments	23,509
Book NOT Tax Expense	FAS106 (68.6% O&M)	(105,455)

Book NOT Tax Expense	Meal Disallowances	25,068
Book NOT Tax Expense	Paid Time Off Equalization	26,912
Book NOT Tax Expense	Redemption Expense Amort	633,851
Book NOT Tax Expense	401(k) ESOP Dividend Deduction	(977,211)
Book NOT Tax Expense	AVA Holding Co - Corporate Restructure	(330,470)
Book NOT Tax Expense	Impairment on LM 2500	2,289,978
Book NOT Tax Expense	Political Contributions	1,097,891
Book NOT Tax Expense	Preferred Dividend Requirement	1,368,281
Book NOT Tax Expense	SERP - Supplemental Executive Retirement Plan	1,098,112
Book NOT Tax Expense	Tax-Exempt Interest Expense - Associated Co (Capital)	-
Book NOT Tax Expense Total		**100,530,141**

Schedule Page: 261 Line No.: 15 Column: b

Income Recorded on Books Not Included in Return

Book NOT Tax Income	AFUDC - Electric	(1,388,432)
Book NOT Tax Income	Boulder Park Disallow - IPUC Order 10/2004	(103,654)
Book NOT Tax Income	Clark Fork PMEs - ED ID	(268,099)
Book NOT Tax Income	CS2 Retention - ED ID	(277,292)
Book NOT Tax Income	Gain General Office Building - ED	(196,092)
Book NOT Tax Income	Grid West/RTO Funding - ED.ID	70,806
Book NOT Tax Income	Grid West/RTO Funding - ED.WA	158,213
Book NOT Tax Income	Idaho PCA	(10,833,675)
Book NOT Tax Income	Injury & Damages - Electric	(295,338)
Book NOT Tax Income	Kettle Falls Disallowance - ED WA	(135,135)
Book NOT Tax Income	NE Tank Spill	(75,085)
Book NOT Tax Income	Nez Perce Settlement - ED ID	5,212
Book NOT Tax Income	Nez Perce Settlement - ED WA	(22,008)
Book NOT Tax Income	Section 199 Manufacturing Deduction	(4,965,269)
Book NOT Tax Income	Unbilled Revenue Add-ons - ED ID	676,702
Book NOT Tax Income	Unbilled Revenue Add-ons - ED WA	862,684
Book NOT Tax Income	WA Deferred Power Costs	14,658,445
Book NOT Tax Income	Wartsilla Units	153,132
Book NOT Tax Income	AFUDC - Gas North	(127,119)
Book NOT Tax Income	Decoupling Mechanism - WA Gas	(819,609)
Book NOT Tax Income	Deferred Gas - GD ID	2,601,001
Book NOT Tax Income	Deferred Gas - GD WA	9,823,279
Book NOT Tax Income	Gain General Office Building - GD	(65,364)
Book NOT Tax Income	Injury & Damages - Gas North	(308,675)
Book NOT Tax Income	Unbilled Revenue Add-ons - GD ID	238
Book NOT Tax Income	Unbilled Revenue Add-ons - GD WA	(4,810)
Book NOT Tax Income	AFUDC - Gas South	(103,552)
Book NOT Tax Income	Deferred Gas - OR	3,561,659
Book NOT Tax Income	DSM - OR	(1,068,900)
Book NOT Tax Income	DSM OR - Amortization - 495600	(132,012)
Book NOT Tax Income	DSM OR - Amortization - 908250	1,747,727
Book NOT Tax Income	Injury & Damages - Oregon	(6,396)
Book NOT Tax Income	Oregon Senate Bill 408 (SB 408)	2,338,488
Book NOT Tax Income	Deferred Compensation Accrual	(683,519)
Book NOT Tax Income	FASB 87 & Retirement Pay Accrual (68.6% O&M)	(1,364,454)
Book NOT Tax Income	Interest Rate Swaps - Amortization	283,279
Book NOT Tax Income	Deferred Compensation Accrual	(171,798)
Book NOT Tax Income	FASB 87 & Retirement Pay Accrual (68.6% O&M)	(342,946)
Book NOT Tax Income	Interest Rate Swaps - Amortization	71,200

Book NOT Tax Income	Deferred Compensation Accrual	(76,644)
Book NOT Tax Income	FASB 87 & Retirement Pay Accrual (68.6% O&M)	(152,999)
Book NOT Tax Income	Interest Rate Swaps - Amortization	31,765
Book NOT Tax Income	Deferred Gas - ID - Interest	52,131
Book NOT Tax Income	Deferred Gas - WA - Interest	(178,609)
Book NOT Tax Income	DFIT on Equity Stock Comp	2,484,467
Book NOT Tax Income	DFIT on Liability Stock Comp	(293,861)
Book NOT Tax Income	Idaho PCA - Interest	(787,859)
Book NOT Tax Income	Kettle Falls Nonoperating - ED ID	(53,138)
Book NOT Tax Income	Kettle Falls Nonoperating - ED ID	-
Book NOT Tax Income	Officers Life Insurance (Cash Surrender)	(865,385)
Book NOT Tax Income	Officer Life Insurance Benefit Accrual	355,878
Book NOT Tax Income	PGE Monetization (Spokane Energy)	8,819,402
Book NOT Tax Income	WA Deferred Power Costs - Interest	(3,023,199)
Book NOT Tax Income	WA Deferred Power Costs - Interest	-
Book NOT Tax Income	Tax-Exempt Interest Income	(544,055)
Book NOT Tax Income	OR Deferred Gas - Interest	(435,940)
Book NOT Tax Income	OR DSM Deferred - Interest	(314,562)
Book NOT Tax Income Total		**18,270,223**

Schedule Page: 261 Line No.: 20 Column: b

Deductions on Return Not Charged Against Book Income

Tax NOT Book Expense	BPA Residential Exchange - ED ID	247,277
Tax NOT Book Expense	BPA Residential Exchange - ED WA	(1,867,860)
Tax NOT Book Expense	Cost of Removal / Salvage - Electric	678,699
Tax NOT Book Expense	DSM Tariff Rider - ED ID	(120,014)
Tax NOT Book Expense	DSM Tariff Rider - ED WA	(2,978,404)
Tax NOT Book Expense	Tax Depreciation - Electric	(84,530,922)
Tax NOT Book Expense	Tax Depreciation - Rathdrum Turbine	(3,850,611)
Tax NOT Book Expense	Cost of Removal / Salvage - Gas North	(107,651)
Tax NOT Book Expense	DSM Tariff Rider - GD ID	620,646
Tax NOT Book Expense	DSM Tariff Rider - GD WA	4,510
Tax NOT Book Expense	Tax Depreciation - Gas North	(17,048,531)
Tax NOT Book Expense	Cost of Removal / Salvage - Oregon	(18,516)
Tax NOT Book Expense	Tax Depreciation - OR Gas	(8,833,966)
Tax NOT Book Expense	Transportation Tax Depr Capitalized	(80,282)
Tax NOT Book Expense	Transportation Tax Depr Capitalized	(687,674)
Tax NOT Book Expense	Transportation Tax Depr Capitalized	(249,080)
Tax NOT Book Expense	Transportation Tax Depr Capitalized	(172,842)
Tax NOT Book Expense	Transportation Tax Depr Capitalized	(61,823)
Tax NOT Book Expense	Transportation Tax Depr Capitalized	(77,110)
Tax NOT Book Expense	Tax Depreciation - Basic American Foods Non-Utility	(12,785)
Tax NOT Book Expense	Tax Depreciation - Sandpoint Acquisition Adjustment	(458,114)
Tax NOT Book Expense	WPNG Acquisition OR - Book	1,110,572
Tax NOT Book Expense	Tax Amortization WPNG Acquisition - OR	(768,683)
Tax NOT Book Expense Total		**(119,263,165)**

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Avista Corporation	(1) X An Original (2) _ A Resubmission	04/17/2008	2007/Q4

FOOTNOTE DATA

Schedule Page: 310 Line No.: 7 Column: b
BPA Contract Terminates September 30, 2011.

Schedule Page: 310 Line No.: 8 Column: b
BPA Contract Terminates January 1, 2036.

Schedule Page: 310.2 Line No.: 11 Column: b
NorthWestern Energy LLC sale expires October 31, 2008

Schedule Page: 310.2 Line No.: 13 Column: b
Bundled Transmission

Schedule Page: 310.3 Line No.: 7 Column: b
PacifiCorp sale terminates October 31, 2008.

Schedule Page: 310.3 Line No.: 8 Column: b
Peaker, LLC capacity contract terminates December 31, 2016.

Schedule Page: 310.4 Line No.: 4 Column: b
Bundled Transmission

Schedule Page: 310.4 Line No.: 7 Column: b
PPL sale terminates October 31, 2008.

Schedule Page: 310.4 Line No.: 12 Column: b
Puget Sound Energy sale terminates October 31, 2008.

Schedule Page: 310.5 Line No.: 3 Column: b
Contract expires 2014.

Schedule Page: 310.5 Line No.: 11 Column: b
Sovereign Power contract terminates 1-31-2010

Schedule Page: 310.5 Line No.: 12 Column: b
Sovereign Contract terminates 1-31-2010

Schedule Page: 310.6 Line No.: 7 Column: b
Bundled Transmission

Schedule Page: 310.6 Line No.: 8 Column: a
Intracompany Wheeling

Schedule Page: 310.6 Line No.: 8 Column: b
IntraCompany Wheeling terminates 09/30/2023.

Schedule Page: 310.6 Line No.: 9 Column: a
Intracompany generation - sale of ancillary services

Schedule Page: 310.6 Line No.: 9 Column: b
IntraCompany Generation - Sale of Ancillary Services terminates 12/31/2009.

Schedule Page: 310.6 Line No.: 10 Column: b
Estimated revenues - true up in later periods.

FOOTNOTE DATA

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

Terminates 2019

Schedule Page: 326 Line No.: 10 Column: l

NOn Monetary

Schedule Page: 326 Line No.: 12 Column: l

Ancilary Services - Spin & Supplemental

Schedule Page: 326 Line No.: 13 Column: l

Non Monetary

Schedule Page: 326.1 Line No.: 7 Column: l

Prior Period

Schedule Page: 326.1 Line No.: 13 Column: l

Non Monetary

Schedule Page: 326.2 Line No.: 14 Column: b

Service to Deer Lake customers delivered from Inland Power & Light.

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

Non Monetary

Schedule Page: 326.4 Line No.: 8 Column: l

Non Monetary

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

Ancilary Services

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

Use of Facility charges

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

Prior Period

Schedule Page: 332 Line No.: 6 Column: g

Prior period and Overun penalty

Schedule Page: 332 Line No.: 8 Column: g

O&M services for Capacity rights

Schedule Page: 332 Line No.: 15 Column: g

Prior Period

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

Schedule Page: 335 Line No.: 5

Vendor	Purpose	Amount
VENDORS LESS THAN $5,000		84,989
ADP INVESTOR COMMUNICATION SERVICES INC	General Services	25396
ADVENTURES IN ADVERTISING	Miscellaneous	10997
AZAR'S FOOD SERVICES	Miscellaneous	8935
BANK OF NY - PERSHING	Treasury Fee	230337
BANK OF NY - SPEC FIN PRODUCTS	Treasury Fee	18336
BOWNE OF LOS ANGELES INC	Miscellaneous	18865
CALIFORNIA INDEPENDENT SYSTEM OPERATOR	Miscellaneous	4584
CAREY INTERNATIONAL INC	Miscellaneous	9917
CITIBANK NA	Treasury Fee	32871
CITY OF SPOKANE	Miscellaneous	14117
COPYRIGHT CLEARANCE CENTER INC	Miscellaneous	4888
CORP CREDIT CARD	Subscriptions	60001
CT CORPORATION	License Fees	4048
DEUTSCHE BANK TRUST COMPANY AMERICAS	Treasury Fee	42617
DOUBLETREE HOTEL SPOKANE CITY CENTER	Miscellaneous	9275
FITCH RATINGS	Rating Agency Fees	27503
GANNETT FLEMING COMPANIES	Professional Services	4759
GARY ELY	Employee Misc Expenses	13514
GEORGESON INC	General Services	5927
HYATT REGENCY WASHINGTON	Board Meeting	23341
KAREN S FELTES	Employee Misc Expenses	6110
MALYN K MALQUIST	Employee Misc Expenses	8948
MARIAN MCMAHON DURKIN	Miscellaneous	4189
MICHAEL G ANDREA	Miscellaneous	7764
MOODYS INVESTORS SERVICE	Rating Agency Fees	65274
NYSE MARKET INC	General Services	36028
RIA	Miscellaneous	4494
ROGER D WOODWORTH	Employee Misc Expenses	5368
ROSS PRINTING COMPANY	Annual Report	16453
RUNNING Y RANCH	Miscellaneous	10885
SCOTT L MORRIS	Employee Misc Expenses	11808
STANDARD & POORS	Rating Agency Fees	45336
SUMTOTAL SYSTEMS INC	Miscellaneous	5611
THE BANK OF NEW YORK	Rating Agency Fees	137091
THE COEUR D ALENE	Miscellaneous	15952
THE DAVENPORT HOTEL	Miscellaneous	5244
THELEN REID & PRIEST LLP	Legal Services	7609
THELEN REID BROWN RAYSMAN & STEINER LLP	Legal Services	5697
THINKING CAP	Miscellaneous	30707
UNION BANK OF CALIFORNIA	Rating Agency Fees	6322
WATSON WYATT & COMPANY	Professional Services	6910
WILMINGTON TRUST COMPANY	Miscellaneous	3667

Schedule Page: 335 Line No.: 9 Column: b

Schedule Page: 335 Line No.: 9

Directors	2007 Expenses
HEIDI B STANLEY	$26,485
ERIK J ANDERSON	$80,274
KRISTIANNE BLAKE	$63,776
JOHN F KELLY	$60,318
MICHAEL L NOEL	$54,059
R JOHN TAYLOR	$54,059
JACK W GUSTAVEL	$3,089
LURA J POWELL	$42,362
ROY EIGUREN	$80,403
	$464,825

Schedule Page: 402 Line No.: -1 Column: b

Operated by Portland General Electric.

Schedule Page: 402 Line No.: -1 Column: e

Joint project operated by PPL Montana LLC.

Schedule Page: 402 Line No.: -1 Column: f

Avista purchased plant from Lessor 9/20/2005

Schedule Page: 406 Line No.: -2 Column: b

License period from August 1, 1972 to July 31, 2007. Extended one year 07-08.

Schedule Page: 406 Line No.: -2 Column: c

License period from August 1, 1972 to July 31, 2007. Extended one year 07-08.

Schedule Page: 406 Line No.: -2 Column: d

License period from March 1, 2001 to February 28, 2046

Schedule Page: 406 Line No.: -2 Column: e

License period from March 1, 2001 to February 28, 2046.

Schedule Page: 406 Line No.: -2 Column: f

License period from August 1, 1972 to July 31, 2007. Extended one year 07-08.

Schedule Page: 406.1 Line No.: -2 Column: b

License period from August 1, 1972 to July 31, 2007. Extended one year 07-08.

Schedule Page: 406.1 Line No.: -2 Column: c

Licensed period from August 1, 1972 to July 31, 2007. Extended one year 07-08.

Schedule Page: 406.1 Line No.: -2 Column: d

Not a licensed project.

RECEIVED
08 APR 28 AM 9:09
IDAHO PUBLIC
UTILITIES COMMISSION

AVU-E

Avista Corp.

2007 Form 1
State Supplements

WASHINGTON

Name of Respondent	This Report Is:	Date of Report	Year of Report
1 Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2007

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Accounts 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Un-Classified; and Account 106, Completed Construction Not Classified - Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
5. Classify Account106 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 of unclassified retirements. Attach supplemental statement showing the account distributions of these tentative classifications in columns (c) and (d), including the

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	0	-
3	(302) Franchises and Consents	0	-
4	(303) Miscellaneous Intangible Plant	149,355	375,508
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	149,355	375,508
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	941,300	
9	(311) Structures and Improvements	24,524,529	74,512
10	(312) Boiler Plant Equipment	40,210,927	186,994
11	(313) Engines and Engine Driven Generators	0	-
12	(314) Turbogenerator Units	13,095,463	184,012
13	(315) Accessory Electric Equipment	10,261,817	5,480
14	(316) Misc. Power Plant Equipment	2,318,767	9,548
15	(317) Asset Retirement Costs for Steam Production	1,114,206	(663,519)
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	92,467,008	(202,973)
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	0	
19	(321) Structures and Improvements	0	
20	(322) Reactor Plant Equipment	0	
21	(323) Turbogenerator Units	0	
22	(324) Accessory Electric Equipment	0	
23	(325) Misc. Power Plant Equipment	0	
24	(326) Asset Retirement Costs for Nuclear Production	0	
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	0	-
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	7,038,614	
28	(331) Structures and Improvements	15,385,953	105,496
29	(332) Reservoirs, Dams, and Waterways	48,673,342	1,817
30	(333) Water Wheels, Turbines, and Generators	34,365,484	46,287
31	(334) Accessory Electric Equipment	9,619,651	409,774
32	(335) Misc. Power Plant Equipment	947,246	22,867
33	(336) Roads, Railroads, and Bridges	675,629	
34	(337) Asset Retirement Costs for Hydraulic Production	0	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	116,705,919	586,241
36	D. Other Production Plant		
37	(340) Land and Land Rights	281,436	
38	(341) Structures and Improvements	981,334	
39	(342) Fuel Holders, Products and Accessories	236,662	
40	(343) Prime Movers	18,218,452	
41	(344) Generators	32,692,219	15,889
42	(345) Accessory Electric Equipment	604,314	151,684

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission		December 31, 2007

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

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

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, acquistion adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

7. For Account 399, state the nature and use of plant included in the 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 also date of such filing.

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			0	(301)	2
			0	(302)	3
			524,863	(303)	4
0	0	0	524,863		5
					6
					7
			941,300	(310)	8
			24,599,041	(311)	9
86,641			40,311,280	(312)	10
			0	(313)	11
0			13,279,475	(314)	12
			10,267,297	(315)	13
4,346			2,323,969	(316)	14
			450,687	(317)	15
90,987	0	0	92,173,049		16
					17
			0	(320)	18
			0	(321)	19
			0	(322)	20
			0	(323)	21
			0	(324)	22
			0	(325)	23
			0	(326)	24
0	0	0	0		25
					26
			7,038,614	(330)	27
17,723			15,473,726	(331)	28
			48,675,159	(332)	29
			34,411,771	(333)	30
167,954			9,861,471	(334)	31
			970,113	(335)	32
			675,629	(336)	33
			0	(337)	34
185,677	0	0	117,106,483		35
					36
0			281,436	(340)	37
			981,334	(341)	38
			236,662	(342)	39
			18,218,452	(343)	40
5,784			32,702,324	(344)	41
10,736		0	745,262	(345)	42

State of Washington

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	39,447

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, 106)

Line No.	Account (a)		Balance at Beginning of Year (g)	Additions (c)
43	(346)	Misc. Power Plant Equipment	255,189	72,525
44	(347)	Asset Retirement Costs for Other Production	0	
45		TOTAL Other Production Plant (Enter Total of lines 37 thru 44)	53,269,606	240,098
46		TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 45)	262,442,533	623,366
47		3. TRANSMISSION PLANT		
48	(350)	Land and Land Rights	7,792,399	518,043
49	(352)	Structures and Improvements	7,182,113	109,799
50	(353)	Station Equipment	71,689,607	2,273,057
51	(354)	Towers and Fixtures	499,054	
52	(355)	Poles and Fixtures	49,681,551	24,099,742
53	(356)	Overhead Conductors and Devices	31,482,868	25,864,701
54	(357)	Underground Conduit	561,148	
55	(358)	Underground Conductors and Devices	1,317,910	
56	(359)	Roads and Trails	85,366	
57	(359.1)	Asset Retirement Costs for Transmission Plant	0	
58		TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	170,292,016	52,865,342
59		4. DISTRIBUTION PLANT		
60	(360)	Land and Land Rights	2,914,591	65,636
61	(361)	Structures and Improvements	7,458,354	213,865
62	(362)	Station Equipment	51,070,961	1,009,796
63	(363)	Storage Battery Equipment	0	-
64	(364)	Poles, Towers, and Fixtures	107,006,394	5,713,027
65	(365)	Overhead Conductors and Devices	69,165,883	2,582,210
66	(366)	Underground Conduit	37,032,800	2,468,709
67	(367)	Underground Conductors and Devices	62,420,081	5,411,187
68	(368)	Line Transformers	89,041,042	8,869,970
69	(369)	Services	61,414,616	3,230,671
70	(370)	Meters	15,591,764	1,802,276
71	(371)	Installations on Customer Premises	0	
72	(372)	Leased Property on Customer Premises	0	
73	(373)	Street Lighting and Signal Systems	13,747,049	835,254
74	(374)	Asset Retiremetn Costs for Distribution Plant	0	
75		TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	516,863,534	32,202,601
76		5. GENERAL PLANT		
77	(389)	Land and Land Rights	0	
78	(390)	Structures and Improvements	426,959	-
79	(391)	Office Furniture and Equipment	0	
80	(392)	Transportation Equipment	3,205,737	516,877
81	(393)	Stores Equipment	21,952	
82	(394)	Tools, Shop and Garage Equipment	1,100,924	187,986
83	(395)	Laboratory Equipment	358,753	
84	(396)	Power Operated Equipment	9,287,333	882,614
85	(397)	Communication Equipment	4,346,009	942,389
86	(398)	Miscellaneous Equipment	0	
87		SUBTOTAL (Enter Total of lines 77 thru 86)	18,747,667	2,529,866
88	(399)	Other Tangible Property	0	
89	(399.1)	Asset Retirement Costs for Genereal Plant	0	
90		TOTAL General Plant (Enter Total of lines 87 thru 89)	18,747,667	2,529,866
91		TOTAL (Accounts 101 and 106)	968,495,105	88,596,684
92	(102)	Electric Plant Purchased	0	-
93	(Less)	(102) Electric Plant Sold	0	
94	(103)	Experimental Plant Unclassified	0	-
95		TOTAL Electric Plant in Service	968,495,105	88,596,684

State of Washington

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2007

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

Retirements *(d)*	Adjustments *(e)*	Transfers *(f)*	Balance at End of Year *(g)*		Line No.
			327,714	(346)	43
			0	(347)	44
16,520	0	0	53,493,184		45
293,184	0	0	262,772,716		46
					47
0			8,310,442	(350)	48
7,317			7,284,595	(352)	49
327,954		0	73,634,710	(353)	50
			499,054	(354)	51
123,972		0	73,657,321	(355)	52
97,194		0	57,250,375	(356)	53
			561,148	(357)	54
			1,317,910	(358)	55
			85,366	(359)	56
			0	(359.1)	57
556,437	0	0	222,600,921		58
					59
3,682			2,976,545	(360)	60
21,253			7,650,966	(361)	61
468,663		67,849	51,679,943	(362)	62
			0	(363)	63
107,425		0	112,611,996	(364)	64
79,790		594	71,668,897	(365)	65
28,338		878	39,474,049	(366)	66
309,260		2,512	67,524,520	(367)	67
1,214,880			96,696,132	(368)	68
74,525		2	64,570,764	(369)	69
2,421,734			14,972,306	(370)	70
			0	(371)	71
			0	(372)	72
77,230		1	14,505,074	(373)	73
			0	(374)	74
4,806,780	0	71,836	544,331,192		75
					76
			0	(389)	77
			426,959	(390)	78
			0	(391)	79
114,617			3,607,997	(392)	80
			21,952	(393)	81
14,764			1,274,146	(394)	82
612			358,141	(395)	83
322,164			9,847,783	(396)	84
544		0	5,287,854	(397)	85
			0	(398)	86
452,701	0	0	20,824,832		87
			0	(399)	88
			0	(399.1)	89
452,701	0	0	20,824,832		90
6,109,102	0	71,836	1,051,054,523		91
			0	(102)	92
			0		93
			0	(103)	94
6,109,102	0	71,836	1,051,054,523		95

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	April 18, 2008	Dec. 31, 2007

ELECTRIC OPERATING REVENUES (Account 400)

1. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.

2. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.

3. If previous year (columns (c), (e), and (g), are not derived from previously reported figures, explain any inconsistencies in a footnote.

Line No.	Title of Account (a)	OPERATING REVENUES Amount for Year (b)	Amount for Previous Year (c)
1	Sales of Electricity		
2	(440) Residential Sales	169,146,869	160,231,038
3	(442) Commercial and Industrial Sales (3)		
4	Small (or Commercial)	157,579,999	157,200,672
5	Large (or Industrial)	42,183,687	41,335,190
6	(444) Public Street and Highway Lighting	3,749,898	3,627,865
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	738,638	732,964
10	TOTAL Sales to Ultimate Consumers	373,399,091 (1)	363,127,729
11	(447) Sales for Resale	123,192,795	160,120,645
12	TOTAL Sales of Electricity	496,591,886	523,248,374
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Provision for Refunds	496,591,886	523,248,374
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	363,079	280,713
18	(453) Sales of Water and Water Power	309,017	230,504
19	(454) Rent from Electric Property	1,978,656	1,825,262
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	2,762,464	38,906,736
22	(456.1) Revenues from Transmission of Electricty of Others	5,266,099	
23			
24			
25			
26	TOTAL Other Operating Revenues	10,679,315	41,243,215
27	TOTAL Electric Operating Revenues	$507,271,201	$564,491,589

State of Washington

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	April 18, 2008	Dec. 31, 2007

ELECTRIC OPERATING REVENUES (Account 400) (Continued)

4. Commercial and Industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classifcation is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)

5. See page 108, Important Changes During Year, for important new territory added and important rate increases or decreases.

6. For lines 2, 4, 5, and 6, see page 304 for amounts relating to unbilled revenue by accounts.

7. Include unmetered sales. Provide details of such sales in a foonote.

MEGAWATT HOURS SOLD		AVG. NO. OF CUSTOMERS PER MONTH		
Amount for Year (d)	Amount for Previous Year (e)	Number for Year (f)	Number for Previous Year (g)	Line No.
				1
2,480,153	2,431,601	205,056	201,276	2
				3
2,136,034	2,134,250	22,460	22,158	4
835,046	817,901	900	894	5
16,818	16,652	300	292	6
				7
				8
11,089	11,013	42	41	9
5,479,140 (2)	5,411,417	228,758	224,661	10
2,309,007	3,246,674		38	11
7,788,147	8,658,091	228,758	224,699	12
				13
7,788,147	8,658,091	228,758	224,699	14

(1) Includes $178,008 of unbilled revenues.

(2) Includes (3,363) MWH relating to unbilled revenues.

(3) Segregation of Commerical and Industrial made on basis of utilization of energy and not on size of account.

Name of Respondent	This Report Is:		Date of Report	Year of Report
	(1) [X]	An Original		
Avista Cor	(2) [ ]	A Resubmission	April 18, 2008	December 31, 2007

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Prior Year (c)
1	(1) POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation	-	-
4	(500) Operation Supervision and Engineering	130,610	139,983
5	(501) Fuel	10,203,721	10,784,256
6	(502) Steam Expenses	538,724	514,671
7	(503) Steam from Other Sources	-	-
8	(Less) (504) Steam Transferred-Cr.	-	-
9	(505) Electric Expenses	793,599	772,066
10	(506) Miscellaneous Steam Power Expenses	435,070	403,048
11	(507) Rents	-	-
12	(509) Allowances	-	-
13	TOTAL Operation (Enter Total of Lines 4 thru 11)	12,101,723	12,614,023
14	Maintenance	-	-
15	(510) Maintenance Supervision and Engineering	76,477	79,088
16	(511) Maintenance of Structures	45,617	50,096
17	(512) Maintenance of Boiler Plant	1,166,733	1,428,261
18	(513) Maintenance of Electric Plant	351,380	204,600
19	(514) Maintenance of Miscellaneous Steam Plant	181,661	168,202
20	TOTAL Maintenance (Enter Total of Lines 14 thru 18)	1,821,869	1,930,247
21	TOTAL Power Production Expenses-Steam Plant (Enter Total of lines 12 and 19)	13,923,592	14,544,270
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	-	-
25	(518) Fuel	-	-
26	(519) Coolants and Water	-	-
27	(520) Steam Expenses	-	-
28	(521) Steam from Other Sources	-	-
29	(Less) (522) Steam Transferred-Cr.	-	-
30	(523) Electric Expenses	-	-
31	(524) Miscellaneous Nuclear Power Expenses	-	-
32	(525) Rents	-	-
33	TOTAL Operation (Enter Total of liens 23 thru 31)	-	-
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	-	-
36	(529) Maintenance of Structures	-	-
37	(530) Maintenance of Reactor Plant Equipment	-	-
38	(531) Maintenance of Electric Plant	-	-
39	(532) Maintenance of Miscellaneous Nuclear Plant	-	-
40	TOTAL Maintenance (Enter Total of lines 34 thru 38)	-	-
41	TOTAL Power Production Expenses-Nuclear Power(Enter total of lines 32 and 39)	-	-
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	854,251	940,411
45	(536) Water for Power	474,956	498,379
46	(537) Hydraulic Expenses	1,898,758	1,844,214
47	(538) Electric Expenses	2,288,257	2,195,748
48	(539) Miscellaneous Hydraulic Power Generation Expenses	257,179	271,040
49	(540) Rents	730,547	641,611
50	TOTAL Operation (Enter Total of lines 43 thru 48)	6,503,948	6,391,405

Name of Respondent	This Report Is:			Date of Report	Year of Report
	(1)	X	An Original		
Avista Cor	(2)		A Resubmission	April 18, 2008	December 31, 2007

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Current Year (b)	mount for Previous Ye (c)
50	C. Hydraulic Power Generation (Continued)		
51	Maintenance		
52	(541) Maintenance Supervision and Engineering	170,151	147,070
53	(542) Maintenance of Structures	84,583	113,970
54	(543) Maintenance of Reservoirs, Dams, and Waterways	832,965	435,697
55	(544) Maintenance of Electric Plant	605,252	515,586
56	(545) Maintenance of Miscellaneous Hydraulic Plant	69,875	80,545
57	TOTAL Maintenance (Enter Total of lines 52 thru 56)	1,762,826	1,292,868
58	TOTAL Power Production Expenses-Hydraulic Power (Enter total of lines 49 and 57)	8,266,774	7,684,273
59	D. Other Power Generation		
60	Operation		
61	(546) Operation Supervision and Engineering	123,131	165,003
62	(547) Fuel	2,189,080	1,460,041
63	(548) Generation Expenses	117,166	139,136
64	(549) Miscellaneous Other Power Generation Expenses	116,417	116,166
65	(550) Rents	(21,846)	(22,265)
66	TOTAL Operation (Enter Total of lines 61 thru 65)	2,523,948	1,858,080
67	Maintenance		
68	(551) Maintenance Supervision and Engineering	32,441	48,323
69	(552) Maintenance of Structures	4,014	(865,440)
70	(553) Maintenance of Generating and Electric Plant	266,549	356,866
71	(554) Maintenance of Miscellaneous Other Power Generation Plant	60,454	65,042
72	TOTAL Maintenance (Enter Total of lines 68 thru 71)	363,458	(395,210)
73	TOTAL Power Production Expenses-Other Power (Enter Total of lines 66 and 72)	2,887,405	1,462,871
74	E. Other Power Supply Expenses		
75	(555) Purchased Power	123,448,443	131,714,783
76	(556) System Control and Load Dispatching	310,400	420,493
77	(557) Other Expenses	29,555,295	68,623,876
78	TOTAL Other Power Supply Expenses (Enter Total of lines 75 thru 77)	153,314,139	200,759,151
79	TOTAL Power Production Expenses (Enter Total of lines 20, 40, 58, 73 and 78)	178,391,910	224,450,565
80	2. TRANSMISSION EXPENSES		
81	Operation		
82	(560) Operation Supervision and Engineering	1,549,830	1,125,845
83	(561) Load Dispatching	1,229,881	1,271,288
84	(561.1) Load Dispatching Reliability	-	10,673
85	(561.2) Load Dispatching Monitor and Operate Transmission System	-	756,744
86	(561.3) Load Dispatching Transmission Service and Sched	-	507,452
87	(561.4) Scheduling Sysemt Control and Dispatch Services	-	-
88	(561.5) Reliability, Planning and Standards Development	-	-
89	(561.6) Transmission Service Studies	-	-
90	(561.7) Generation Interconnection Studies	-	-
91	(561.8) Reliability, Planning and Standards Development Services	-	-
92	(562) Station Expenses	59,833	171,885
93	(563) Overhead Line Expenses	51,866	45,462
94	(564) Underground Line Expenses	-	-
95	(565) Transmission of Electricity by Others	8,947,833	7,821,504
96	(566) Miscellaneous Transmission Expenses	565,932	474,416
97	(567) Rents	5,838	27,644
98	TOTAL Operation (Enter Total of lines 82 thru 89)	12,411,013	12,212,913
99	Maintenance		
100	(568) Maintenance Supervision and Engineering	348,402	297,767
101	(569) Maintenance of Structures	165,859	81,609
102	(570) Maintenance of Station Equipment	714,078	877,832
103	(571) Maintenance of Overhead Lines	203,023	147,315
104	(572) Maintenance of Underground Lines	11,075	2,805
105	(573) Maintenance of Miscellaneous Transmission Plant	64,645	35,167
106	TOTAL Maintenance (Enter Total of lines 92 thru 97)	1,507,082	1,442,495
107	TOTAL Transmission Expenses (Enter Total of lines 90 and 98)	13,918,095	13,655,409
108	3. DISTRIBUTION EXPENSES		
109	Operation		
110	(580) Operation Supervision and Engineering	705,495	620,718

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp	(1) [X] An Original (2) [ ] A Resubmission	April 18, 2008	December 31, 2007

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Current Year (b)	Amount for Prior Year (c)
103	3. DISTRIBUTION EXPENSES (Continued)		
104	(581) Load Dispatching	-	-
105	(582) Station Expenses	264,375	241,907
106	(583) Overhead Line Expenses	666,440	737,220
107	(584) Underground Line Expenses	860,249	885,131
108	(585) Street Lighting and Signal System Expenses	70,073	57,563
109	(586) Meter Expenses	1,071,686	895,819
110	(587) Customer Installations Expenses	476,221	494,245
111	(588) Miscellaneous Distribution Expenses	3,064,584	3,031,597
112	(589) Rents	99,728	95,365
113	TOTAL Operation (Enter Total of lines 102 thru 112)	7,278,852	7,059,565
114	Maintenance		
115	(590) Maintenance Supervision and Engineering	846,576	974,197
116	(591) Maintenance of Structures	180,727	190,092
117	(592) Maintenance of Station Equipment	700,669	724,580
118	(593) Maintenance of Overhead Lines	3,584,234	4,758,276
119	(594) Maintenance of Underground Lines	793,324	764,838
120	(595) Maintenance of Line Transformers	494,527	443,579
121	(596) Maintenance of Street Lighting and Signal Systems	411,842	293,064
122	(597) Maintenance of Meters	94,061	76,442
123	(598) Maintenance of Miscellaneous Distribution Plant	266,697	253,826
124	TOTAL Maintenance (Enter Total of lines 115 thru 123)	7,372,658	8,478,892
125	TOTAL Distribution Expenses (Enter Total of lines 113 and 124)	14,651,509	15,538,457
126	4. CUSTOMER ACCOUNTS EXPENSES		
127	Operation		
128	(901) Supervision	351,719	337,233
129	(902) Meter Reading Expenses	1,777,494	1,728,782
130	(903) Customer Records and Collection Expenses	5,341,001	5,790,728
131	(904) Uncollectible Accounts	1,077,906	1,013,427
132	(905) Miscellaneous Customer Accounts Expenses	125,274	120,036
133	TOTAL Customer Accounts Expenses (Enter Total of lines 128 thru 132)	8,673,395	8,990,206
134	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
135	Operation		
136	(907) Supervision	-	-
137	(908) Customer Assistance Expenses	7,346,340	7,624,298
138	(909) Informational and Instructional Expenses	48,535	44,214
139	(910) Miscellaneous Customer Service and Informational Expenses	77,192	70,562
140	TOTAL Cust. Service and Informational Expenses (Enter Total of lines 136 thru 139)	7,472,067	7,739,074
141	6. SALES EXPENSES		
142	Operation		
143	(911) Supervision	-	-
144	(912) Demonstrating and Selling Expenses	319,777	333,599
145	(913) Advertising Expenses	172,832	178,745
146	(916) Miscellaneous Sales Expenses	189,302	143,953
147	TOTAL Sales Expenses (Enter Total of lines 143 thru 146)	681,911	656,297
148	7. ADMINISTRATIVE AND GENERAL EXPENSES		
149	Operation		
150	(920) Administrative and General Salaries	12,626,039	11,493,206
151	(921) Office Supplies and Expenses	2,365,374	2,791,875
152	(Less) (922) Administrative expenses Transferred-Credit	(22,764)	(18,576)

Name of Respondent	This Report Is:			Date of Report	Year of Report
	(1)	X	An Original		
Avista Corp	(2)		A Resubmission	April 18, 2008	December 31, 2007

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Current Year (b)	Amount for Prior Year (c)
153	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
154	(923) Outside Services Employed	7,608,147	6,613,135
155	(924) Property Insurance	734,617	788,820
156	(925) Injuries and Damages	2,143,356	2,495,688
157	(926) Employee Pensions and Benefits	675,530	758,281
158	(927) Franchise Requirements	-	-
159	(928) Regulatory Commission Expenses	2,818,994	1,186,343
160	(Less) (929) Duplicate Charges-Cr.	-	-
161	(930.1) General Advertising Expenses	2,116,427	8,679
162	(930.2) Miscellaneous General Expenses	-	2,027,828
163	(931) Rents	455,372	707,526
164	TOTAL Operation (Enter Total of lines 150 thru 163)	31,521,094	28,852,805
165	Maintenance		
166	(935) Maintenance of General Plant	5,249,301	4,435,303
167	TOTAL Administrative and General Expenses (Enter Total of lines 164 and 166)	36,770,395	33,288,108
168	TOTAL Electric Operation and Maintenance Expenses (Enter Total of lines 79,99,125,133,140,147,and 167)	260,559,282	304,318,115

NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES

1. The data on number of empl construction employees in a footnote.
for the payroll period ending neare 3. The number of employees assignable to the electric
payroll period ending 60 days befc department from joint functions of combination utilities may
2. If the respondent's payroll for be determined by estimate, on the basis of employee equiva-
cludes any special construction lents. Show the estimated number of equivalent employees
employees on line 3, and show th attributed to the electric department from joint functions.

1 Payroll Period Ended (Date) December 31, 2007		
2 Total Regular Full-Time Employees	393	396
3 Total Part-Time and Temporary Employees	18	24
4 Allocation of General Employees	218	231
5 Total Employees (See Note 1)	629	651

State of Washington

Name of Respondent	This report is:	Date of Report (Mo, Da, Yr)	Year of Report
Avista Corp.	(1) (X)An Original (2) ( ) A Resubmission	04/18/2008	Dec. 31, 2007

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uni-form System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole, wood or steel; (2) H-frame, wood, or steel poles; (3) tower; or (4) underground construc-tion. If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated;conversely, show in column(g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicating where other than 60 cycle,3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (pole miles) (In the case of underground lines, report circuit miles.) On structure of Line Designated (f)	On structure of Another Line (g)	Number of Circuits (h)
1	Group Sum		60	60		1.00		
2								
3	Group Sum		115	115		935.00		
4								
5	Beacon Sub #4	BPA Bell Sub	230	230	Steel Tower	1.00		1
6	Beacon Sub	BPA Bell Sub	230	230	H Type	5.00		1
7	Beacon Sub #5	BPA Bell Sub	230	230	Steel Pole	4.00		1
8	Beacon Sub #5	BPA Bell Sub	230	230	H Type	2.00		1
9	Beacon	Cabinet Gorge Plant	230	230	Steel Tower		1.00	1
10	Beacon	Cabinet Gorge Plant	230	230	Steel Pole			2
11	Beacon	Cabinet Gorge Plant	230	230	H Type	15.50		1
12	Beacon Sub	Lolo Sub	230	230	Steel Tower	1.00		1
13	Beacon Sub	Lolo Sub	230	230	H Type	21.00		1
14	Benewah	Shawnee	230	230	Steel Pole	15.00		1
15	North Lewiston	Walla Walla	230	230	Steel Tower	4.00		1
16	North Lewiston	Walla Walla	230	230	H Type	31.00		1
17	North Lewiston	Shawnee	230	230	Steel Tower	7.00		1
18	North Lewiston	Shawnee	230	230	H Type	26.00		1
19	Walla Walla	Wanapum	230	230	Alum.			1
20	Walla Walla	Wanapum	230	230	H Type	78.00		1
21								
22								
23	BPA Line	West Side Sub	230	230	Steel Pole	2.00		2
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36								
37								
38								
39					TOTAL	1,148.50	1.00	19

State of Washington

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	04/18/2008	Dec. 31, 2007

TRANSMISSION STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report lower voltage lines and higher voltage lines as one line. Designate in a footnote if you do not include lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms and terms of lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-
9. Designate any transmission line leased to another company and give name of lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in column (j) land, Land Rights, and clearing right-of-way)			Expenses, except Depreciation and Taxes				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
	136,038	70,092	206,130					1
								2
	4,137,548	51,522,677	55,660,225	80,200	249,382		329,582	3
								4
795 McMACSR	17,912	1,334,573	1,352,485					5
1272McMACSR								6
1272 ACSS								7
1272 ACSS	30,323	3,226,063	3,256,386					8
795 McMACSR								9
1590 ACSS								10
795 McMACSR	113,410	15,741,949	15,855,359		6,934		6,934	11
795 McMACSR								12
1272 McMAL	92,558	1,352,229	1,444,787		3,551		3,551	13
1590 ACSS	569,739	46,617,039	47,186,778		1,478		1,478	14
1272 McMAL								15
1272 McMAL	598,166	4,759,454	5,357,620	1,262	3,280		4,542	16
1272 McMAL								17
1272 McMAL	862,135	7,391,738	8,253,873	8,720	2,017		10,737	18
1272 McMAL								19
1272 McMAL	70,781	2,461,474	2,532,255	1,993	4,847		6,840	20
								21
								22
1272 McMAL	36,461	587,224	623,685					23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
								36
								37
								38
	6,665,071	135,064,512	141,729,583	92,175	271,489	0	363,664	39

Data Request for Statistics Report - 2007

		Total Company Operations		Washington Operations	
Line No		2007	2006	2007	2006
1	Electric Service Revenues				
2					
3	Residential Sales	251,356,668	234,714,224	169,146,869	160,231,038
4	Commercial & Industrial Sales	319,386,474	314,154,243	199,763,686	198,535,862
5	Public Street & Highway Lighting	5,516,824	5,268,037	3,749,898	3,627,865
6	Interdepartmental Sales	856,061	849,076	738,638	732,964
7	Sales for Resale	138,609,644	175,572,595	123,192,795	160,120,645
8	Other Operating Revenues	28,405,882	66,996,908	10,679,315	41,243,215
9					
10					
11	Total Electric Service Revenues	744,131,553	797,555,083	507,271,201	564,491,589
12					
13	Disposition of Energy-Megawatt Hrs.				
14					
15	Residential Sales	3,670,026	3,577,694	2,480,153	2,431,601
16	Commercial & Industrial Sales	5,216,440	5,171,749	2,971,080	2,952,151
17	Public Street & Highway Lighting	25,418	24,783	16,818	16,652
18	Interdepartmental Sales	12,842	12,776	11,089	11,013
19	Sales for Resale	2,536,103	3,552,362	2,309,007	3,246,674
20	Energy Losses				
21					
22	Total Disposition of Energy	11,460,829	12,339,364	7,788,147	8,658,091
23					
24	Average Number of Electric Customers Per Month				
25					
26	Residential Sales	306,737	300,940	205,056	201,276
27	Commercial & Industrial Sales	39,865	39,300	23,360	23,052
28	Public Street & Highway Lighting	426	425	300	292
29	Interdepartmental Sales	69	67	42	41
31					
32					
33					
34	Miles of Transmission Pole Lines (Rounded)	2,150	2,135	1,149	1,134
35	Number of Line Transformers	109,869	107,624	76,129	75,762
36	Capacity of All Line Transformers (KVA - Rounded)	4,485	4,352	3,470	3,357
37	Number of Meters	368,182	356,506	247,843	239,211

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	April 18, 2008	December 31, 2007

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

Line No.	Item (a)	Total (b)	Electric (c)
1	UTILITY PLANT		
2	In Service		
3	Plant in Service (Classified)	796,823,282	670,684,893
4	Property Under Capital Leases	1,646,656	
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Investment in Kettle Falls		
8	TOTAL (Enter Total of lines 3 thru 7)	798,469,938	670,684,893
9	Leased to Others		
10	Held for Future Use	39,828	
11	Construction Work in Progress	3,250,034	1,383,832
12	Acquisition Adjustments	0	0
13	TOTAL Utility Plant (Enter Total of lines 8 thru 12)	801,759,800	672,068,725
14	Accum. Prov. for Depr., Amort., & Depl.	0	0
15	Net Utility Plant (Enter total of line 13 less 14)	801,759,800	672,068,725
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION		
17	In Service:		
18	Depreciation		
19	Amort. and Depl. of Producing Nat. Gas Land and Land Rights		
20	Accumulated Depreciation - Kettle Falls		
21	Amort. of Other Utility Plant		
22	TOTAL in Service (Enter Total of lines 18 thru 21)		
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	TOTAL Leased to Others (Enter Total of lines 24 and 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	TOTAL Held for Future Use (Ent. Tot. of lines 28 and 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort. of Plant Acquisition Adjustment	0	0
33	TOTAL Accumulated Provisions (Should agree with line 14 above) (Enter Total of lines 22, 26, 30, 31, and 32)	0	0

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	April 18, 2008	December 31, 2007

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

Gas *(d)*	Other (Specify) *(e)*	Other (Specify) *(f)*	Other (Specify) *(g)*	Common *(h)*	Line No.
					1
					2
120,785,323				5,353,066	3
403,189				1,243,467	4
					5
					6
					7
121,188,512				6,596,533	8
					9
39,828					10
1,863,078				3,124	11
					12
123,091,418				6,599,657	13
0					14
123,091,418				6,599,657	15
					16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
0				0	33

Name of Respondent	This Report Is:	Date of Report	Year of Report
2 Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2007

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Accounts 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified - Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
5. Classify Account106 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 of unclassified retirements. Attach supplemental statement showing the account distributions of these tentative classifications in columns (c) and (d), including the

Line No.		Account *(a)*	Balance at Beginning of Year *(b)*	Additions *(c)*
1		1. INTANGIBLE PLANT		
2	(301)	Organization	0	
3	(302)	Franchises and Consents	9,036,684	
4	(303)	Miscellaneous Intangible Plant	0	
5		TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	9,036,684	-
6		2. PRODUCTION PLANT		
7		A. Steam Production Plant		
8	(310)	Land and Land Rights	0	
9	(311)	Structures and Improvements	0	
10	(312)	Boiler Plant Equipment	0	
11	(313)	Engines and Engine Driven Generators	0	
12	(314)	Turbogenerator Units	0	
13	(315)	Accessory Electric Equipment	0	
14	(316)	Misc. Power Plant Equipment	0	
15	(317)	Asset Retirement Costs for Steam Production	0	
16		TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)		-
17		B. Nuclear Production Plant		
18	(320)	Land and Land Rights	0	
19	(321)	Structures and Improvements	0	
20	(322)	Reactor Plant Equipment	0	
21	(323)	Turbogenerator Units	0	
22	(324)	Accessory Electric Equipment	0	
23	(325)	Misc. Power Plant Equipment	0	
24	(326)	Asset Retirement Costs for Nuclear Production	0	
25		TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	0	-
26		C. Hydraulic Production Plant		
27	(330)	Land and Land Rights	6,056,374	253,886
28	(331)	Structures and Improvements	10,225,832	365,729
29	(332)	Reservoirs, Dams, and Waterways	26,293,101	4,030,270
30	(333)	Water Wheels, Turbines, and Generators	34,237,881	5,954,716
31	(334)	Accessory Electric Equipment	6,127,258	1,000
32	(335)	Misc. Power Plant Equipment	2,651,246	15,279
33	(336)	Roads, Railroads, and Bridges	1,098,564	
34	(337)	Asset Retirement Costs for Hydraulic Production	0	
35		TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	86,690,256	10,620,880
36		D. Other Production Plant		
37	(340)	Land and Land Rights	621,682	
38	(341)	Structures and Improvements	3,186,951	
39	(342)	Fuel Holders, Products and Accessories	1,700,144	
40	(343)	Prime Movers	3,658,328	
41	(344)	Generators	48,574,276	58,691
42	(345)	Accessory Electric Equipment	1,868,084	2,581

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2007

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

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

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, acquistion adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

7. For Account 399, state the nature and use of plant included in the 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 also date of such filing.

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			0	(301)	2
			9,036,684	(302)	3
			0	(303)	4
0	0	0	9,036,684		5
					6
					7
			0	(310)	8
			0	(311)	9
			0	(312)	10
			0	(313)	11
			0	(314)	12
			0	(315)	13
			0	(316)	14
			0	(317)	15
0	0	0	0		16
					17
			0	(320)	18
			0	(321)	19
			0	(322)	20
			0	(323)	21
			0	(324)	22
			0	(325)	23
			0	(326)	24
0	0	0	0		25
					26
			6,310,260	(330)	27
4,709			10,586,852	(331)	28
21,887			30,301,484	(332)	29
606,738			39,585,859	(333)	30
42,099			6,086,159	(334)	31
90,994			2,575,531	(335)	32
			1,098,564	(336)	33
			0	(337)	34
766,427	0	0	96,544,709		35
					36
			621,682	(340)	37
			3,186,951	(341)	38
			1,700,144	(342)	39
			3,658,328	(343)	40
			48,632,967	(344)	41
0			1,870,665	(345)	42

State of Idaho

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2007

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, 106)

Line No.		Account (a)	Balance at Beginning of Year (b)	Additions (c)
43	(346)	Misc. Power Plant Equipment	0	
44	(347)	Asset Retirement Costs for Other Production	0	
45		TOTAL Other Production Plant (Enter Total of lines 37 thru 45)	59,609,465	61,272
46		TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 45)	146,299,721	10,682,152
47		3. TRANSMISSION PLANT		
48	(350)	Land and Land Rights	4,258,849	234,906
49	(352)	Structures and Improvements	6,144,464	1,317,389
50	(353)	Station Equipment	63,624,891	6,417,497
51	(354)	Towers and Fixtures	556,655	0
52	(355)	Poles and Fixtures	43,814,261	627,646
53	(356)	Overhead Conductors and Devices	26,759,971	542,808
54	(357)	Underground Conduit	0	0
55	(358)	Underground Conductors and Devices	0	0
56	(359)	Roads and Trails	1,374,002	
57	(359.1)	Asset Retirement Costs for Transmission Plant	0	
58		TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	146,533,093	9,140,246
59		4. DISTRIBUTION PLANT		
60	(360)	Land and Land Rights	819,234	151,882
61	(361)	Structures and Improvements	2,771,562	419,601
62	(362)	Station Equipment	27,920,810	1,817,770
63	(363)	Storage Battery Equipment	0	0
64	(364)	Poles, Towers, and Fixtures	68,421,492	4,639,718
65	(365)	Overhead Conductors and Devices	46,495,385	3,392,387
66	(366)	Underground Conduit	24,854,500	1,555,357
67	(367)	Underground Conductors and Devices	35,850,946	3,703,807
68	(368)	Line Transformers	50,419,881	3,979,183
69	(369)	Services	38,376,889	2,293,831
70	(370)	Meters	8,131,116	244,479
71	(371)	Installations on Customer Premises	0	0
72	(372)	Leased Property on Customer Premises	0	0
73	(373)	Street Lighting and Signal Systems	10,852,542	967,961
74	(374)	Asset Retirement Costs for Distribution Plant	0	
75		TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	314,914,358	23,165,976
76		5. GENERAL PLANT		
77	(389)	Land and Land Rights	101,907	
78	(390)	Structures and Improvements	1,017,107	108,811
79	(391)	Office Furniture and Equipment	0	0
80	(392)	Transportation Equipment	1,293,057	156,059
81	(393)	Stores Equipment	30,140	0
82	(394)	Tools, Shop and Garage Equipment	422,808	16,402
83	(395)	Laboratory Equipment	314,854	0
84	(396)	Power Operated Equipment	5,679,833	44,713
85	(397)	Communication Equipment	2,404,789	1,388,792
86	(398)	Miscellaneous Equipment	2,785	0
87		SUBTOTAL (Enter Total of lines 77 thru 86)	11,267,279	1,714,777
88	(399)	Other Tangible Property	0	
89	(399.1)	Asset Retirement Costs for General Plant	0	
90		TOTAL General Plant (Enter Total of lines 87 and 90)	11,267,279	1,714,777
91		TOTAL (Accounts 101 and 106)	628,051,134	44,703,151
92	(102)	Electric Plant Purchased	0	
93	(Less)	(102) Electric Plant Sold	0	
94	(103)	Experimental Plant Unclassified	0	
95		TOTAL Electric Plant in Service	628,051,134	44,703,151

State of Idaho

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2007

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

Retirements *(d)*	Adjustments *(e)*	Transfers *(f)*	Balance at End of Year *(g)*		Line No.
			0	(346)	43
			0	(347)	44
0	0	0	59,670,737		45
766,427	0	0	156,215,446		46
					47
			4,493,755	(350)	48
			7,461,853	(352)	49
326,094		0	69,716,294	(353)	50
			556,655	(354)	51
19,356		0	44,422,551	(355)	52
6,642		0	27,296,137	(356)	53
			0	(357)	54
			0	(358)	55
			1,374,002	(359)	56
			0	(359.1)	57
352,092	0	0	155,321,247		58
					59
			971,116	(360)	60
0			3,191,163	(361)	61
100,246		(67,849)	29,570,485	(362)	62
0			0	(363)	63
138,279			72,922,931	(364)	64
72,914		(594)	49,814,264	(365)	65
26,824		(878)	26,382,155	(366)	66
240,762		(2,512)	39,311,479	(367)	67
34,805			54,364,259	(368)	68
56,343		(2)	40,614,375	(369)	69
			8,375,595	(370)	70
			0	(371)	71
			0	(372)	72
62,585		(1)	11,757,917	(373)	73
			0	(374)	74
732,758	0	(71,836)	337,275,739		75
					76
			101,907	(389)	77
0			1,125,918	(390)	78
0			0	(391)	79
52,413			1,396,703	(392)	80
0			30,140	(393)	81
5,650			433,560	(394)	82
767			314,087	(395)	83
351,507			5,373,039	(396)	84
0		0	3,793,581	(397)	85
0			2,785	(398)	86
410,337	0	0	12,571,720		87
			0	(399)	88
			0	(399.1)	89
410,337	0	0	12,571,720		90
2,261,614	0	(71,836)	670,420,836		91
			0	(102)	92
			0		93
			0	(103)	94
2,261,614	0	(71,836)	670,420,836		95

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	April 18, 2008	Dec. 31, 2007

ELECTRIC OPERATING REVENUES (Account 400)

1. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.

2. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.

3. If previous year (columns (c), (e), and (g), are not derived from previously reported figures, explain any inconsistencies in a footnote.

Line No.	Title of Account (a)	OPERATING REVENUES Amount for Year (b)	Amount for Previous Year (c)
1	Sales of Electricity		
2	(440) Residential Sales	82,202,981	74,476,039
3	(442) Commercial and Industrial Sales (3)		
4	Small (or Commercial)	66,597,380	63,990,388
5	Large (or Industrial)	53,023,256	51,625,770
6	(444) Public Street and Highway Lighting	1,766,926	1,640,172
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	109,758	108,667
10	TOTAL Sales to Ultimate Consumers	203,700,301 (1)	191,841,036
11	(447) Sales for Resale	665,530	853,338
12	TOTAL Sales of Electricity	204,365,831	192,694,374
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Provision for Refunds	204,365,831	192,694,374
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	195,158	166,620
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	766,116	721,856
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	265,133	5,703,285
22	(456.1) Revenues from Transmission of Electricty of Others	5,183,591	
23			
24			
25			
26	TOTAL Other Operating Revenues	6,409,998	6,591,761
27	TOTAL Electric Operating Revenues	$210,775,829	$199,286,135

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ELECTRIC OPERATING REVENUES (Account 400) (Continued)

4. Commercial and Industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classifcation is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)

5. See page 108, Important Changes During Year, for important new territory added and important rate increases or decreases.

6. For lines 2, 4, 5, and 6, see page 304 for amounts relating to unbilled revenue by accounts.

7. Include unmetered sales. Provide details of such sales in a foonote.

MEGAWATT HOURS SOLD		AVG. NO. OF CUSTOMERS PER MONTH		
Amount for Year (d)	Amount for Previous Year (e)	Number for Year (f)	Number for Previous Year (g)	Line No.
				1
1,189,723	1,145,935	101,671	99,653	2
				3
996,001	975,577	16,027	15,753	4
1,249,326	1,243,987	477	494	5
8,600	8,131	126	133	6
				7
				8
1,631	1,648	19	19	9
3,445,281 (2)	3,375,278	118,320	116,052	10
20,002	30,029		2	11
3,465,283	3,405,307	118,320	116,054	12
				13
3,465,283	3,405,307	118,320	116,054	14

(1) Includes $865,383 of unbilled revenues.

(2) Includes 3,934 MWH relating to unbilled revenues.

(3) Segregation of Commerical and Industrial made on basis of utilization of energy and not on size of account.

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SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate Schedule (a)	MWH Sold (b)	Revenue (c)	Average Number of Customers (d)	KWH of Sales per Customer (e)	Revenue (cents) per KWH Sold (f)
1	**RESIDENTIAL SALES (440)**					
2	1 Residential Service	1,146,820	77,147,609	96,954	11,828	6.73
3	2 Residential Service					
4	3 Residential Service					
5	12 Res. & Farm Gen. Service	20,253	1,789,297	4,132	4,902	8.83
6	22 Res. & Farm Lg. Gen. Service	14,009	791,145	23	609,087	5.65
7	30 Pumping-Special					
8	32 Res. & Farm Pumping Service	3,698	275,129	562	6,580	7.44
9	48 Res. & Farm Area Lighting	1,262	218,540			17.32
10	49 Area Lighting-High-Press.	285	63,456			22.27
11	56 Centralia Credit					
12	95 Wind Power		46,733			
13	73 Residential					
14	74 Residential Service					
15	76 Residential Service					
16	77 Residential Service					
17	79 Residential Service					
18	58 Tax Adjustment		1,079,154			
19	Total	1,186,327	81,411,063	101,671	11,668	6.91
20	Residential-Unbilled	3,396	791,918			
21	**COMMERCIAL SALES (442)**					
22	2 General Service					
23	3 General Service					
24	11 General Service	299,821	23,596,895	14,284	20,990	7.87
25	19 Contract-General Service					
26	21 Large General Service	590,582	36,197,058	1,303	453,248	6.13
27	25 Extra Lg. Gen. Service	73,749	3,145,630	3	24,583,000	4.27
28	28 Contract-Extra Large Service					
29	31 Pumping Service	28,436	1,809,201	437	65,071	6.36
30	47 Area Lighting-Sod. Vap.	1,077	130,075			12.08
31	49 Area Lighting-High-Press.	2,294	407,074			17.75
32	56 Centralia Credit					
33	95 Wind Power		9,833			
34	73 General Service					
35	74 Large General Service					
36	75 Large General Service					
37	76 Large General Service					
38	77 General Service					
39	79 Area Light-High Press.					
40	58 Tax Adjustment		1,247,465			
41	Total	995,959	66,543,231	16,027	62,143	6.69
42	Commercial-Unbilled	42	54,149			
43	Total Billed	2,182,286	147,954,294	117,698		6.78
44	Total Unbilled Rev. (See Instr. 6)	3,438	846,067	0		24.61
45	TOTAL	2,185,724	148,800,361	117,698		6.81

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2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," page 301. If the sales under any rate schedule are classified in more than one revenue account, list the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate Schedule (a)	MWH Sold (b)	Revenue (c)	Average Number of Customers (d)	KWH of Sales per Customer (e)	Revenue (cents) per KWH Sold (f)
1	**INDUSTRIAL SALES (442)**					
2	2 General Service					
3	3 General Service					
4	8 Lg Gen Time of Use					
5	11 General Service	3,935	331,970	130	30,269	8.44
6	21 Large General Service	78,253	4,672,908	81	966,086	5.97
7	25 Extra Lg. Gen. Service	1,139,662	46,214,503	11	103,605,636	4.06
8	28 Contract-Extra Large Service					
9	29 Contract Lg. Gen. Service					
10	30 Pumping Service -Special					
11	31 Pumping Service	23,738	1,501,027	216	109,898	6.32
12	32 Pumping Svc Res & Frm	3,175	200,272	39	81,410	6.31
13	47 Area Lighting-Sod. Vap.	63	7,160			11.37
14	49 Area Lighting-High-Press.	47	7,709			16.40
15	56 Centralia Credit					
16	72 General Service					
17	73 General Service					
18	74 Large General Service					
19	75 Large General Service					
20	76 Pumping Service					
21	77 General Service					
22	78 Lg Gen Tim of Use					
23	58 Tax Adjustment		79,051			
24	Total	1,248,873	53,014,600	477	2,618,182	4.24
25	Industrial-Unbilled	453	8,656	0		
26						
27	**STREET AND HWY LIGHTING (444)**					
28	11 General Service					
29	41 Co.-Owned St. Lt. Service	117	15,086	5	23,400	12.89
30	42 Co.-Owned St. Lt. Service	6515	1549865	90	72,389	23.79
31	High-Press. Sod. Vap.					
32	43 Cust.-Owned St. Lt. Energy	35	2,892	1	35,000	8.26
33	and Maint. Service					
34	44 Cust.-Owned St. Lt. Energy	590	73,269	17	34,706	12.42
35	and Maint. Svce.-High-					
36	Press. Sod. Vap.					
37	45 Cust.Owned St. Lt. Energy Service	281	14,912	3	93,667	5.31
38	46 Cust.Owned St. Lt. Energy Service	1,019	72,206	10	101,900	7.09
39	High-Press. Sod. Vap.					
40	56 Centralia Credit					
41	58 Tax Adjustment		28,036			
42	Total	8,557	1,756,266	126	67,913	5.93
43	Street and Hwy Lighting-Unbilled	43	10,660			
44	Total Billed	3,439,716	202,725,160	118,301		5.89
45	Total Unbilled Rev. (See Instr. 6)	3,934	865,383	0		22.00
46	TOTAL	3,443,650	203,590,543	118,301		5.91

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SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate Schedule (a)	MWH Sold (b)	Revenue (c)	Average Number of Customers (d)	KWH of Sales per Customer (e)	Revenue (cents) per KWH Sold (f)
1	**OTHER SALES TO PUBLIC**					
2	**AUTHORITIES (445)**					
3	None					
4						
5	**INTERDEPARTMENTAL**					
6	**SALES (448)**	1,631	109,758	19	85,842	6.73
7	58 Tax Adjustment					
8	Total	1,631	109,758	19	85,842	6.73
9						
10	**SALES FOR RESALE (447) (1)**					
11	61 Sales to Other Utilities - ID	20,002	665,530			
12						
13						
14						
14	Total	20,002	665,530			
15						
16						
17	Note: Sch. 61 is a state assigned rate schedule for Sales/Resale					
18						
19						
20						
21						
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28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39	Total Billed	3,461,349	203,500,448	118,320	29,254	5.88
40	Total Unbilled Rev.	3,934	865,383	0		22.00
41	TOTAL	3,465,283	204,365,831	118,320	29,287	5.90

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Prior Year (c)
1	(1) POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	-	-
5	(501) Fuel	-	-
6	(502) Steam Expenses	-	-
7	(503) Steam from Other Sources	-	-
8	(Less) (504) Steam Transferred-Cr.	-	-
9	(505) Electric Expenses	-	-
10	(506) Miscellaneous Steam Power Expenses	26,809	33,357
11	(507) Rents	-	-
12	(509) Allowances	-	-
13	TOTAL Operation (Enter Total of Lines 4 thru 11)	26,809	33,357
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	-	-
16	(511) Maintenance of Structures	-	-
17	(512) Maintenance of Boiler Plant	-	-
18	(513) Maintenance of Electric Plant	-	-
19	(514) Maintenance of Miscellaneous Steam Plant	-	-
20	TOTAL Maintenance (Enter Total of Lines 14 thru 18)	-	-
21	TOTAL Power Production Expenses-Steam Plant (Enter Total of	26,809	33,357
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	-	-
25	(518) Fuel	-	-
26	(519) Coolants and Water	-	-
27	(520) Steam Expenses	-	-
28	(521) Steam from Other Sources	-	-
29	(Less) (522) Steam Transferred-Cr.	-	-
30	(523) Electric Expenses	-	-
31	(524) Miscellaneous Nuclear Power Expenses	-	-
32	(525) Rents	-	-
33	TOTAL Operation (Enter Total of liens 23 thru 31)	-	-
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	-	-
36	(529) Maintenance of Structures	-	-
37	(530) Maintenance of Reactor Plant Equipment	-	-
38	(531) Maintenance of Electric Plant	-	-
39	(532) Maintenance of Miscellaneous Nuclear Plant	-	-
40	TOTAL Maintenance (Enter Total of lines 34 thru 38)	-	-
41	TOTAL Power Production Expenses-Nuclear Power(Enter total o	-	-
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	717,192	534,370
45	(536) Water for Power	260,384	258,691
46	(537) Hydraulic Expenses	773,463	750,076
47	(538) Electric Expenses	1,298,931	1,330,985
48	(539) Miscellaneous Hydraulic Power Generation Expenses	313,222	291,202
49	(540) Rents	24,490	22,747
50	TOTAL Operation (Enter Total of lines 43 thru 48)	3,387,682	3,188,071

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
50	C. Hydraulic Power Generation (Continued)		
51	Maintenance		
52	(541) Maintenance Supervision and Engineering	74,597	136,022
53	(542) Maintenance of Structures	104,297	127,789
54	(543) Maintenance of Reservoirs, Dams, and Waterways	489,048	134,952
55	(544) Maintenance of Electric Plant	698,707	760,676
56	(545) Maintenance of Miscellaneous Hydraulic Plant	40,770	109,274
57	TOTAL Maintenance (Enter Total of lines 52 thru 56)	1,407,419	1,268,713
58	TOTAL Power Production Expenses-Hydraulic Power (Enter total	4,795,101	4,456,783
59	D. Other Power Generation		
60	Operation		
61	(546) Operation Supervision and Engineering	59,922	75,115
62	(547) Fuel	1,774,127	1,655,935
63	(548) Generation Expenses	131,564	120,501
64	(549) Miscellaneous Other Power Generation Expenses	305,120	215,489
65	(550) Rents	(11,976)	(11,557)
66	TOTAL Operation (Enter Total of lines 61 thru 65)	2,258,757	2,055,484
67	Maintenance		
68	(551) Maintenance Supervision and Engineering	27,113	6,110
69	(552) Maintenance of Structures	984	17,482
70	(553) Maintenance of Generating and Electric Plant	113,087	57,533
71	(554) Maintenance of Miscellaneous Other Power Generation Plant	103,451	110,005
72	TOTAL Maintenance (Enter Total of lines 68 thru 71)	244,636	191,130
73	TOTAL Power Production Expenses-Other Power (Enter Total of l	2,503,393	2,246,613
74	E. Other Power Supply Expenses		
75	(555) Purchased Power	67,677,804	68,368,436
76	(556) System Control and Load Dispatching	170,170	218,263
77	(557) Other Expenses	(2,598,752)	18,609,778
78	TOTAL Other Power Supply Expenses (Enter Total of lines 75 thr	65,249,222	87,196,477
79	TOTAL Power Production Expenses (Enter Total of lines 20, 40, 5	72,574,525	93,933,231
80	2. TRANSMISSION EXPENSES		
81	Operation		
82	(560) Operation Supervision and Engineering	833,681	548,228
83	(561) Load Dispatching	673,726	657,026
84	(561.1) Load Dispatching Reliability	-	5,540
85	(561.2) Load Dispatching Monitor and Operate Transmission System	-	390,517
86	(561.3) Load Dispatching Transmission Service and Sched	-	263,400
87	(561.4) Scheduling Sysemt Control and Dispatch Services	-	-
88	(561.5) Reliability, Planning and Standards Development	-	-
89	(561.6) Transmission Service Studies	-	-
90	(561.7) Generation Interconnection Studies	-	-
91	(561.8) Reliability, Planning and Standards Development Services	-	-
92	(562) Station Expenses	69,524	85,369
93	(563) Overhead Line Expenses	63,877	66,030
94	(564) Underground Line Expenses	-	-
95	(565) Transmission of Electricity by Others	4,905,446	4,059,863
96	(566) Miscellaneous Transmission Expenses	312,386	244,325
97	(567) Rents	3,200	14,349
98	TOTAL Operation (Enter Total of lines 82 thru 89)	6,861,839	6,334,647
99	Maintenance		
100	(568) Maintenance Supervision and Engineering	107,540	91,728
101	(569) Maintenance of Structures	152,665	104,065
102	(570) Maintenance of Station Equipment	216,557	181,341
103	(571) Maintenance of Overhead Lines	406,653	458,974
104	(572) Maintenance of Underground Lines	-	3,001
105	(573) Maintenance of Miscellaneous Transmission Plant	35,274	19,120
106	TOTAL Maintenance (Enter Total of lines 92 thru 97)	918,689	858,229
107	TOTAL Transmission Expenses (Enter Total of lines 90 and 98)	7,780,528	7,192,876
108	3. DISTRIBUTION EXPENSES		
109	Operation		
110	(580) Operation Supervision and Engineering	380,998	293,458

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Current Year (b)	Amount for Prior Year (c)
103	3. DISTRIBUTION EXPENSES (Continued)		
104	(581) Load Dispatching	-	-
105	(582) Station Expenses	191,631	157,769
106	(583) Overhead Line Expenses	205,664	11,385
107	(584) Underground Line Expenses	539,789	498,697
108	(585) Street Lighting and Signal System Expenses	139,770	115,798
109	(586) Meter Expenses	(163,269)	(12,856)
110	(587) Customer Installations Expenses	410,704	422,091
111	(588) Miscellaneous Distribution Expenses	1,549,678	1,353,687
112	(589) Rents	52,633	42,662
113	TOTAL Operation (Enter Total of lines 102 thru 112)	3,307,599	2,882,689
114	Maintenance		
115	(590) Maintenance Supervision and Engineering	488,118	513,607
116	(591) Maintenance of Structures	88,938	73,497
117	(592) Maintenance of Station Equipment	172,321	195,423
118	(593) Maintenance of Overhead Lines	3,134,265	2,711,401
119	(594) Maintenance of Underground Lines	271,102	291,011
120	(595) Maintenance of Line Transformers	56,235	54,269
121	(596) Maintenance of Street Lighting and Signal Systems	147,910	96,827
122	(597) Maintenance of Meters	82,786	87,732
123	(598) Maintenance of Miscellaneous Distribution Plant	85,922	124,143
124	TOTAL Maintenance (Enter Total of lines 115 thru 123)	4,527,595	4,147,910
125	TOTAL Distribution Expenses (Enter Total of lines 113 and 124)	7,835,194	7,030,599
126	4. CUSTOMER ACCOUNTS EXPENSES		
127	Operation		
128	(901) Supervision	181,949	174,315
129	(902) Meter Reading Expenses	360,704	686,250
130	(903) Customer Records and Collection Expenses	2,651,442	2,927,898
131	(904) Uncollectible Accounts	557,614	523,839
132	(905) Miscellaneous Customer Accounts Expenses	64,805	62,046
133	TOTAL Customer Accounts Expenses (Enter Total of lines 128 th	3,816,514	4,374,348
134	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
135	Operation		
136	(907) Supervision	-	-
137	(908) Customer Assistance Expenses	3,834,782	3,773,471
138	(909) Informational and Instructional Expenses	17,111	15,687
139	(910) Miscellaneous Customer Service and Informational Expenses	39,932	36,474
140	TOTAL Cust. Service and Informational Expenses (Enter Total of	3,891,826	3,825,631
141	6. SALES EXPENSES		
142	Operation		
143	(911) Supervision	-	-
144	(912) Demonstrating and Selling Expenses	181,813	187,773
145	(913) Advertising Expenses	85,997	86,793
146	(916) Miscellaneous Sales Expenses	9	-
147	TOTAL Sales Expenses (Enter Total of lines 143 thru 146)	267,819	274,565
148	7. ADMINISTRATIVE AND GENERAL EXPENSES		
149	Operation		
150	(920) Administrative and General Salaries	6,761,163	5,919,473
151	(921) Office Supplies and Expenses	1,268,126	1,425,626
152	(Less) (922) Administrative expenses Transferred-Credit	(12,205)	(9,480)

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Current Year (b)	Amount for Prior Year (c)
153	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
154	(923) Outside Services Employed	4,079,254	3,374,986
155	(924) Property Insurance	393,879	402,571
156	(925) Injuries and Damages	1,146,285	1,273,664
157	(926) Employee Pensions and Benefits	316,075	347,888
158	(927) Franchise Requirements	6,327	6,230
159	(928) Regulatory Commission Expenses	1,496,154	700,607
160	(Less) (929) Duplicate Charges-Cr.	-	-
161	(930.1) General Advertising Expenses	980,183	-
162	(930.2) Miscellaneous General Expenses	-	922,385
163	(931) Rents	243,464	360,538
164	TOTAL Operation (Enter Total of lines 150 thru 163)	16,678,704	14,724,488
165	Maintenance		
166	(935) Maintenance of General Plant	1,860,751	1,495,039
167	TOTAL Administrative and General Expenses (Enter Total of lines	18,539,455	16,219,527
168	TOTAL Electric Operation and Maintenance Expenses (Enter Tot	114,705,862	132,850,777
	79,99,125,133,140,147,and 167)		

NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES

1. The data on number of empl construction employees in a footnote.
for the payroll period ending neare 3. The number of employees assignable to the electric
payroll period ending 60 days befo department from joint functions of combination utilities may
2. If the respondent's payroll for be determined by estimate, on the basis of employee equiva-
cludes any special construction lents. Show the estimated number of equivalent employees
employees on line 3, and show th attributed to the electric department from joint functions.

1 Payroll Period Ended (Date) December 31, 2007		
2 Total Regular Full-Time Employees	86	84
3 Total Part-Time and Temporary Employees	5	6
4 Allocation of General Employees	119	106
5 Total Employees (See Note 1)	210	196

OREGON

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
4 Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission		December 31, 2007

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.

2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Accounts 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified - Electric.

3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.

4. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.

5. Classify Account106 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 of unclassified retirements. Attach supplemental statement showing the account distributions of these tentative classifications in columns (c) and (d), including the

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	0	
3	(302) Franchises and Consents	0	
4	(303) Miscellaneous Intangible Plant	163,809	0
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	163,809	0
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	0	
9	(311) Structures and Improvements	0	
10	(312) Boiler Plant Equipment	0	
11	(313) Engines and Engine Driven Generators	0	
12	(314) Turbogenerator Units.	0	
13	(315) Accessory Electric Equipment	0	
14	(316) Misc. Power Plant Equipment	0	
15	(317) Asset Retirement Costs for Steam Production	0	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	0	0
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	0	
19	(321) Structures and Improvements	0	
20	(322) Reactor Plant Equipment	0	
21	(323) Turbogenerator Units	0	
22	(324) Accessory Electric Equipment	0	
23	(325) Misc. Power Plant Equipment	0	
24	(326) Asset Retirement Costs for Nuclear Production	0	
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	0	0
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	0	
28	(331) Structures and Improvements	0	
29	(332) Reservoirs, Dams, and Waterways	0	
30	(333) Water Wheels, Turbines, and Generators	0	
31	(334) Accessory Electric Equipment	0	
32	(335) Misc. Power Plant Equipment	0	
33	(336) Roads, Railroads, and Bridges	0	
34	(337) Asset Retirement Costs for Hydraulic Production	0	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	0	0
36	D. Other Production Plant		
37	(340) Land and Land Rights	0	
38	(341) Structures and Improvements	11,294,927	44,210
39	(342) Fuel Holders, Products and Accessories	19,127,625	0
40	(343) Prime Movers	0	
41	(344) Generators	115,542,040	6,359
42	(345) Accessory Electric Equipment	12,489,964	0

State of Oregon

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2007

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

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

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, acquistion adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

7. For Account 399, state the nature and use of plant included in the 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 also date of such filing.

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			0	(301)	2
			0	(302)	3
			163,809	(303)	4
0	0	0	163,809		5
					6
					7
			0	(310)	8
			0	(311)	9
			0	(312)	10
			0	(313)	11
			0	(314)	12
			0	(315)	13
			0	(316)	14
			0	(317)	15
0	0	0	0		16
					17
			0	(320)	18
			0	(321)	19
			0	(322)	20
			0	(323)	21
			0	(324)	22
			0	(325)	23
			0	(326)	24
0	0	0	0		25
					26
			0	(330)	27
			0	(331)	28
			0	(332)	29
			0	(333)	30
			0	(334)	31
			0	(335)	32
			0	(336)	33
			0	(337)	34
0	0	0	0		35
					36
			0	(340)	37
			11,339,137	(341)	38
0			19,127,625	(342)	39
			0	(343)	40
0			115,548,399	(344)	41
			12,489,964	(345)	42

State of Oregon

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission		December 31, 2007

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, 106)

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)
43	(346) Misc. Power Plant Equipment	1,002,760	10,693
44	(347) Asset Retirement Costs for Other Production	351,682	0
45	TOTAL Other Production Plant (Enter Total of lines 37 thru 44)	159,808,998	61,262
46	TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 45)	159,808,998	61,262
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	60,302	
49	(352) Structures and Improvements	0	
50	(353) Station Equipment	8,517,295	302,927
51	(354) Towers and Fixtures	0	
52	(355) Poles and Fixtures	993,472	
53	(356) Overhead Conductors and Devices	303,976	0
54	(357) Underground Conduit	0	
55	(358) Underground Conductors and Devices	0	
56	(359) Roads and Trails	0	
57	(359.1) Asset Retirement Costs for Transmission Plant	0	
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	9,875,045	302,927
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	0	
61	(361) Structures and Improvements	0	
62	(362) Station Equipment	0	
63	(363) Storage Battery Equipment	0	
64	(364) Poles, Towers, and Fixtures	0	
65	(365) Overhead Conductors and Devices	0	
66	(366) Underground Conduit	0	
67	(367) Underground Conductors and Devices	0	
68	(368) Line Transformers	0	
69	(369) Services	0	
70	(370) Meters	0	
71	(371) Installations on Customer Premises	0	
72	(372) Leased Property on Customer Premises	0	
73	(373) Street Lighting and Signal Systems	0	
74	(374) Asset Retirement Costs for Distribution Plant	0	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	0	0
76	5. GENERAL PLANT		
77	(389) Land and Land Rights	0	
78	(390) Structures and Improvements	0	
79	(391) Office Furniture and Equipment	0	
80	(392) Transportation Equipment	0	
81	(393) Stores Equipment	0	
82	(394) Tools, Shop and Garage Equipment	0	
83	(395) Laboratory Equipment	0	
84	(396) Power Operated Equipment	0	
85	(397) Communication Equipment	0	
86	(398) Miscellaneous Equipment	0	
87	SUBTOTAL (Enter Total of lines 77 thru 86)	0	0
88	(399) Other Tangible Property	0	
89	(399.1) Asset Retirement Costs for General Plant	0	
90	TOTAL General Plant (Enter Total of lines 88 and 89)	0	0
91	TOTAL (Accounts 101 and 106)	169,847,852	364,189
92	(102) Electric Plant Purchased	0	
93	(Less) (102) Electric Plant Sold	0	
94	(103) Experimental Plant Unclassified	0	
95	TOTAL Electric Plant in Service	169,847,852	364,189

State of Oregon

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2007

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
			1,013,453	(346)	43
			351,682	(347)	44
0	0	0	159,870,260		45
0	0	0	159,870,260		46
					47
			60,302	(350)	48
			0	(352)	49
1,405,805			7,414,417	(353)	50
			0	(354)	51
			993,472	(355)	52
			303,976	(356)	53
			0	(357)	54
			0	(358)	55
			0	(359)	56
			0	(359.1)	57
1,405,805	0	0	8,772,167		58
					59
			0	(360)	60
			0	(361)	61
			0	(362)	62
			0	(363)	63
			0	(364)	64
			0	(365)	65
			0	(366)	66
			0	(367)	67
			0	(368)	68
			0	(369)	69
			0	(370)	70
			0	(371)	71
			0	(372)	72
			0	(373)	73
			0	(374)	74
0	0	0	0		75
					76
			0	(389)	77
			0	(390)	78
			0	(391)	79
			0	(392)	80
			0	(393)	81
			0	(394)	82
			0	(395)	83
			0	(396)	84
		0	0	(397)	85
			0	(398)	86
0	0	0	0		87
			0	(399)	88
			0	(399.1)	89
0	0	0	0		90
1,405,805	0	0	168,806,236		91
			0	(102)	92
			0		93
			0	(103)	94
1,405,805	0	0	168,806,236		95

State of Oregon

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	April 18, 2008	Dec. 31, 2007

ELECTRIC OPERATING REVENUES (Account 400)

1. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.

2. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.

3. If previous year (columns (c), (e), and (g), are not derived from previously reported figures, explain any inconsistencies in a footnote.

Line No.	Title of Account (a)	OPERATING REVENUES Amount for Year (b)	OPERATING REVENUES Amount for Previous Year (c)
1	Sales of Electricity		
2	(440) Residential Sales		
3	(442) Commercial and Industrial Sales (3)		
4	Small (or Commercial)		
5	Large (or Industrial)		
6	(444) Public Street and Highway Lighting		
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers		
11	(447) Sales for Resale		
12	TOTAL Sales of Electricity		
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Provision for Refunds		
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues		
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property		
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	11,238,771	19,017,891
22	(456.1) Revenues from Transmission of Electricty of Others		
23			
24			
25			
26	TOTAL Other Operating Revenues	11,238,771	19,017,891
27	TOTAL Electric Operating Revenues	$11,238,771	$19,017,891

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	April 18, 2008	Dec. 31, 2007

ELECTRIC OPERATING REVENUES (Account 400) (Continued)

4. Commercial and Industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classifcation is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)

5. See page 108, Important Changes During Year, for important new territory added and important rate increases or decreases.

6. For lines 2, 4, 5, and 6, see page 304 for amounts relating to unbilled revenue by accounts.

7. Include unmetered sales. Provide details of such sales in a foonote.

MEGAWATT HOURS SOLD		AVG. NO. OF CUSTOMERS PER MONTH		
Amount for Year (d)	Amount for Previous Year (e)	Number for Year (f)	Number for Previous Year (g)	Line No.
				1
				2
				3
				4
				5
				6
				7
				8
				9
				10
				11
				12
				13
				14

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp	(1) [X] An Original (2) [ ] A Resubmission	April 18, 2008	December 31, 2007

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Prior Year (c)
1	(1) POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	-	-
5	(501) Fuel	-	-
6	(502) Steam Expenses	-	-
7	(503) Steam from Other Sources	-	-
8	(Less) (504) Steam Transferred-Cr.	-	-
9	(505) Electric Expenses	-	-
10	(506) Miscellaneous Steam Power Expenses	-	-
11	(507) Rents	-	-
12	(509) Allowances	-	-
13	TOTAL Operation (Enter Total of Lines 4 thru 11)	-	-
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	-	-
16	(511) Maintenance of Structures	-	-
17	(512) Maintenance of Boiler Plant	-	-
18	(513) Maintenance of Electric Plant	-	-
19	(514) Maintenance of Miscellaneous Steam Plant	-	-
20	TOTAL Maintenance (Enter Total of Lines 14 thru 18)	-	-
21	TOTAL Power Production Expenses-Steam Plant (Enter Total of lines 12	-	-
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	-	-
25	(518) Fuel	-	-
26	(519) Coolants and Water	-	-
27	(520) Steam Expenses	-	-
28	(521) Steam from Other Sources	-	-
29	(Less) (522) Steam Transferred-Cr.	-	-
30	(523) Electric Expenses	-	-
31	(524) Miscellaneous Nuclear Power Expenses	-	-
32	(525) Rents	-	-
33	TOTAL Operation (Enter Total of liens 23 thru 31)	-	-
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	-	-
36	(529) Maintenance of Structures	-	-
37	(530) Maintenance of Reactor Plant Equipment	-	-
38	(531) Maintenance of Electric Plant	-	-
39	(532) Maintenance of Miscellaneous Nuclear Plant	-	-
40	TOTAL Maintenance (Enter Total of lines 34 thru 38)	-	-
41	TOTAL Power Production Expenses-Nuclear Power(Enter total of lines 3	-	-
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	-	-
45	(536) Water for Power	-	-
46	(537) Hydraulic Expenses	-	-
47	(538) Electric Expenses	-	-
48	(539) Miscellaneous Hydraulic Power Generation Expenses	-	-
49	(540) Rents	-	-
50	TOTAL Operation (Enter Total of lines 43 thru 48)	-	-

Name of Respondent	This Report Is:	Date of Report	Year of Report
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ELECTRIC OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
50	C. Hydraulic Power Generation (Continued)		
51	Maintenance		
52	(541) Maintenance Supervision and Engineering	-	-
53	(542) Maintenance of Structures	-	-
54	(543) Maintenance of Reservoirs, Dams, and Waterways	-	-
55	(544) Maintenance of Electric Plant	-	-
56	(545) Maintenance of Miscellaneous Hydraulic Plant	-	-
57	TOTAL Maintenance (Enter Total of lines 52 thru 56)	-	-
58	TOTAL Power Production Expenses-Hydraulic Power (Enter total of lines	-	-
59	D. Other Power Generation		
60	Operation		
61	(546) Operation Supervision and Engineering	1,019,521	776,586
62	(547) Fuel	95,812,681	82,419,671
63	(548) Generation Expenses	1,082,778	1,737,816
64	(549) Miscellaneous Other Power Generation Expenses	22,811	19,223
65	(550) Rents	55,601	66,259
66	TOTAL Operation (Enter Total of lines 61 thru 65)	97,993,392	85,019,554
67	Maintenance		
68	(551) Maintenance Supervision and Engineering	882,651	8,459
69	(552) Maintenance of Structures	-	-
70	(553) Maintenance of Generating and Electric Plant	1,369,934	1,232,448
71	(554) Maintenance of Miscellaneous Other Power Generation Plant	(3,588)	(3,648)
72	TOTAL Maintenance (Enter Total of lines 68 thru 71)	2,248,997	1,237,258
73	TOTAL Power Production Expenses-Other Power (Enter Total of lines 66	100,242,389	86,256,813
74	E. Other Power Supply Expenses		
75	(555) Purchased Power	-	-
76	(556) System Control and Load Dispatching	-	-
77	(557) Other Expenses	-	-
78	TOTAL Other Power Supply Expenses (Enter Total of lines 75 thru 77)	-	-
79	TOTAL Power Production Expenses (Enter Total of lines 20, 40, 58, 73 ar	100,242,389	86,256,813
80	2. TRANSMISSION EXPENSES		
81	Operation		
82	(560) Operation Supervision and Engineering	-	-
83	(561) Load Dispatching	-	-
84	(561.1) Load Dispatching Reliability	-	-
85	(561.2) Load Dispatching Monitor and Operate Transmission System	-	-
86	(561.3) Load Dispatching Transmission Service and Sched	-	-
87	(561.4) Scheduling Sysemt Control and Dispatch Services	-	-
88	(561.5) Reliability, Planning and Standards Development	-	-
89	(561.6) Transmission Service Studies	-	-
90	(561.7) Generation Interconnection Studies	-	-
91	(561.8) Reliability, Planning and Standards Development Services	-	-
92	(562) Station Expenses	34,748	15,994
93	(563) Overhead Line Expenses	-	-
94	(564) Underground Line Expenses	-	-
95	(565) Transmission of Electricity by Others	-	-
96	(566) Miscellaneous Transmission Expenses	-	-
97	(567) Rents	-	-
98	TOTAL Operation (Enter Total of lines 82 thru 89)	34,748	15,994
99	Maintenance		
100	(568) Maintenance Supervision and Engineering	-	-
101	(569) Maintenance of Structures	-	-
102	(570) Maintenance of Station Equipment	-	-
103	(571) Maintenance of Overhead Lines	-	10,433
104	(572) Maintenance of Underground Lines	-	-
105	(573) Maintenance of Miscellaneous Transmission Plant	-	-
106	TOTAL Maintenance (Enter Total of lines 92 thru 97)	-	10,433
107	TOTAL Transmission Expenses (Enter Total of lines 90 and 98)	34,748	26,428
108	3. DISTRIBUTION EXPENSES		
109	Operation		
110	(580) Operation Supervision and Engineering	-	-

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Avista Cor	(2)		A Resubmission	April 18, 2008	December 31, 2007

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Current Year (b)	Amount for Prior Year (c)
103	3. DISTRIBUTION EXPENSES (Continued)		
104	(581) Load Dispatching	-	-
105	(582) Station Expenses	-	-
106	(583) Overhead Line Expenses	-	-
107	(584) Underground Line Expenses	-	-
108	(585) Street Lighting and Signal System Expenses	-	-
109	(586) Meter Expenses	-	-
110	(587) Customer Installations Expenses	-	-
111	(588) Miscellaneous Distribution Expenses	-	-
112	(589) Rents	-	-
113	TOTAL Operation (Enter Total of lines 102 thru 112)	-	-
114	Maintenance		
115	(590) Maintenance Supervision and Engineering	-	-
116	(591) Maintenance of Structures	-	-
117	(592) Maintenance of Station Equipment	-	-
118	(593) Maintenance of Overhead Lines	-	-
119	(594) Maintenance of Underground Lines	-	-
120	(595) Maintenance of Line Transformers	-	-
121	(596) Maintenance of Street Lighting and Signal Systems	-	-
122	(597) Maintenance of Meters	-	-
123	(598) Maintenance of Miscellaneous Distribution Plant	-	-
124	TOTAL Maintenance (Enter Total of lines 115 thru 123)	-	-
125	TOTAL Distribution Expenses (Enter Total of lines 113 and 124)	-	-
126	4. CUSTOMER ACCOUNTS EXPENSES		
127	Operation		
128	(901) Supervision	-	-
129	(902) Meter Reading Expenses	-	-
130	(903) Customer Records and Collection Expenses	-	-
131	(904) Uncollectible Accounts	-	-
132	(905) Miscellaneous Customer Accounts Expenses	-	-
133	TOTAL Customer Accounts Expenses (Enter Total of lines 128 thru 132)	-	-
134	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
135	Operation		
136	(907) Supervision	-	-
137	(908) Customer Assistance Expenses	-	-
138	(909) Informational and Instructional Expenses	-	-
139	(910) Miscellaneous Customer Service and Informational Expenses	-	-
140	TOTAL Cust. Service and Informational Expenses (Enter Total of lines 13	-	-
141	6. SALES EXPENSES		
142	Operation		
143	(911) Supervision	-	-
144	(912) Demonstrating and Selling Expenses	-	-
145	(913) Advertising Expenses	-	-
146	(916) Miscellaneous Sales Expenses	-	-
147	TOTAL Sales Expenses (Enter Total of lines 143 thru 146)	-	-
148	7. ADMINISTRATIVE AND GENERAL EXPENSES		
149	Operation		
150	(920) Administrative and General Salaries	-	-
151	(921) Office Supplies and Expenses	-	-
152	(Less) (922) Administrative expenses Transferred-Credit	-	-

Name of Respondent	This Report Is:			Date of Report	Year of Report
Avista Cor	(1)	X	An Original	April 18, 2008	December 31, 2007
	(2)		A Resubmission		

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Current Year (b)	Amount for Prior Year (c)
153	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
154	(923) Outside Services Employed	-	-
155	(924) Property Insurance	-	-
156	(925) Injuries and Damages	-	-
157	(926) Employee Pensions and Benefits	-	-
158	(927) Franchise Requirements	-	-
159	(928) Regulatory Commission Expenses	-	-
160	(Less) (929) Duplicate Charges-Cr.	-	-
161	(930.1) General Advertising Expenses	-	-
162	(930.2) Miscellaneous General Expenses	-	-
163	(931) Rents	-	-
164	TOTAL Operation (Enter Total of lines 150 thru 163)	-	-
165	Maintenance		
166	(935) Maintenance of General Plant	-	-
167	TOTAL Administrative and General Expenses (Enter Total of lines 164 ar	-	-
168	TOTAL Electric Operation and Maintenance Expenses (Enter Total of line	100,277,137	86,283,240
	79,99,125,133,140,147,and 167)		

NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES

1. The data on number of empl construction employees in a footnote.
for the payroll period ending neare 3. The number of employees assignable to the electric
payroll period ending 60 days befc department from joint functions of combination utilities may
2. If the respondent's payroll for be determined by estimate, on the basis of employee equiva-
cludes any special construction lents. Show the estimated number of equivalent employees
employees on line 3, and show th attributed to the electric department from joint functions.

1 Payroll Period Ended (Date) December 31, 2007		
2 Total Regular Full-Time Employees	-	-
3 Total Part-Time and Temporary Employees	-	-
4 Allocation of General Employees	-	-
5 Total Employees (See Note 1)	-	-

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MONTANA

Name of Respondent	This Report Is:	Date of Report	Year of Report
3 Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	*(Mo, Da, Yr)*	December 31, 2007

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Accounts 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified - Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
5. Classify Account106 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 of unclassified retirements. Attach supplemental statement showing the account distributions of these tentative classifications in columns (c) and (d), including the

Line No.	Account *(a)*	Balance at Beginning of Year *(b)*	Additions *(c)*
1	1. INTANGIBLE PLANT		
2	(301) Organization	0	
3	(302) Franchises and Consents	6,222,448	
4	(303) Miscellaneous Intangible Plant	(20,531)	
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	6,201,917	0
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,296,911	
9	(311) Structures and Improvements	99,987,414	30
10	(312) Boiler Plant Equipment	121,837,148	1,607,553
11	(313) Engines and Engine Driven Generators	0	
12	(314) Turbogenerator Units	33,989,562	2,789,616
13	(315) Accessory Electric Equipment	15,999,915	70,420
14	(316) Misc. Power Plant Equipment	12,912,553	38,810
15	(317) Asset Retirement Costs for Steam Production	134,589	(0)
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	286,158,093	4,506,429
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	0	
19	(321) Structures and Improvements	0	
20	(322) Reactor Plant Equipment	0	
21	(323) Turbogenerator Units	0	
22	(324) Accessory Electric Equipment	0	
23	(325) Misc. Power Plant Equipment	0	
24	(326) Asset Retirement Costs for Nuclear Production	0	
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	0	0
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	42,413,876	238,207
28	(331) Structures and Improvements	12,411,466	925,884
29	(332) Reservoirs, Dams, and Waterways	33,001,627	186,598
30	(333) Water Wheels, Turbines, and Generators	33,266,432	7,851,545
31	(334) Accessory Electric Equipment	12,990,599	10,557
32	(335) Misc. Power Plant Equipment	2,775,435	21,725
33	(336) Roads, Railroads, and Bridges	225,369	
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 35)	137,084,804	9,234,516
36	D. Other Production Plant		
37	(340) Land and Land Rights	0	
38	(341) Structures and Improvements	0	
39	(342) Fuel Holders, Products and Accessories	0	
40	(343) Prime Movers	0	
41	(344) Generators	0	
42	(345) Accessory Electric Equipment	0	

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2007

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

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

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, acquistion adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

7. For Account 399, state the nature and use of plant included in the 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 also date of such filing.

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			0	(301)	2
			6,222,448	(302)	3
0			(20,531)	(303)	4
0	0	0	6,201,917		5
					6
					7
5,304			1,291,607	(310)	8
16,833			99,970,611	(311)	9
2,124,662			121,320,039	(312)	10
			0	(313)	11
1,979,267			34,799,911	(314)	12
4,277			16,066,058	(315)	13
			12,951,363	(316)	14
			134,589	(317)	15
4,130,343	0	0	286,534,178		16
					17
			0	(320)	18
			0	(321)	19
			0	(322)	20
			0	(323)	21
			0	(324)	22
			0	(325)	23
			0	(326)	24
0	0	0	0		25
					26
			42,652,083	(330)	27
6,848			13,330,502	(331)	28
8,276			33,179,949	(332)	29
567,765			40,550,212	(333)	30
0			13,001,156	(334)	31
131,732			2,665,428	(335)	32
			225,369	(336)	33
				(337)	34
714,621	0	0	145,604,699		35
					36
			0	(340)	37
			0	(341)	38
			0	(342)	39
			0	(343)	40
			0	(344)	41
			0	(345)	42

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2007

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, 106)

Line No.	Account *(a)*		Balance at Beginning of Year *(b)*	Additions *(c)*
43	(346)	Misc. Power Plant Equipment	0	
44	(347)	Asset Retirement Costs for Other Production	0	
45		TOTAL Other Production Plant (Enter Total of lines 37 thru 44)	0	0
46		TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 45)	423,242,897	13,740,945
47		3. TRANSMISSION PLANT		
48	(350)	Land and Land Rights	883,384	
49	(352)	Structures and Improvements	461,581	15,926
50	(353)	Station Equipment	16,479,010	380,960
51	(354)	Towers and Fixtures	16,013,530	10,715
52	(355)	Poles and Fixtures	7,173,299	405
53	(356)	Overhead Conductors and Devices	15,745,311	1,328
54	(357)	Underground Conduit	0	
55	(358)	Underground Conductors and Devices	0	
56	(359)	Roads and Trails	367,476	
57	(359.1)	Asset Retirement Costs for Transmission Plant	0	
58		TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	57,123,591	409,334
59		4. DISTRIBUTION PLANT		
60	(360)	Land and Land Rights	0	
61	(361)	Structures and Improvements	15,881	
62	(362)	Station Equipment	152,268	
63	(363)	Storage Battery Equipment	0	
64	(364)	Poles, Towers, and Fixtures	10,080	
65	(365)	Overhead Conductors and Devices	6,676	
66	(366)	Underground Conduit	46	
67	(367)	Underground Conductors and Devices	637	
68	(368)	Line Transformers	897	
69	(369)	Services	127	
70	(370)	Meters	29	
71	(371)	Installations on Customer Premises	0	
72	(372)	Leased Property on Customer Premises	0	
73	(373)	Street Lighting and Signal Systems	0	
74	(374)	Asset Retirement Costs for Distribution Plant	0	
75		TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	186,641	0
76		5. GENERAL PLANT		
77	(389)	Land and Land Rights	0	
78	(390)	Structures and Improvements	0	
79	(391)	Office Furniture and Equipment	0	
80	(392)	Transportation Equipment	174,931	17,502
81	(393)	Stores Equipment	0	
82	(394)	Tools, Shop and Garage Equipment	0	
83	(395)	Laboratory Equipment	0	
84	(396)	Power Operated Equipment	34,660	1,066
85	(397)	Communication Equipment	24,007	667,259
86	(398)	Miscellaneous Equipment	0	
87		SUBTOTAL (Enter Total of lines 77 thru 86)	233,598	685,827
88	(399)	Other Tangible Property	0	
89	(399.1)	Asset Retirement Costs for General Plant	0	
90		TOTAL General Plant (Enter Total of lines 87 thru 89)	233,598	685,827
91		TOTAL (Accounts 101 and 106)	486,988,644	14,836,106
92	(102)	Electric Plant Purchased	0	
93	(Less)	(102) Electric Plant Sold	0	
94	(103)	Experimental Plant Unclassified	0	
95		TOTAL Electric Plant in Service	486,988,644	14,836,106

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2007

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
			0	(346)	43
			0	(347)	44
0	0	0	0		45
4,844,964	0	0	432,138,877		46
					47
			883,384	(350)	48
			477,507	(352)	49
394,620			16,465,350	(353)	50
			16,024,245	(354)	51
134			7,173,570	(355)	52
75			15,746,564	(356)	53
			0	(357)	54
			0	(358)	55
			367,476	(359)	56
			0	(359.1)	57
394,829	0	0	57,138,096		58
					59
			0	(360)	60
			15,881	(361)	61
			152,268	(362)	62
			0	(363)	63
			10,080	(364)	64
			6,676	(365)	65
			46	(366)	66
			637	(367)	67
			897	(368)	68
			127	(369)	69
			29	(370)	70
			0	(371)	71
			0	(372)	72
			0	(373)	73
			0	(374)	74
0	0	0	186,641		75
					76
			0	(389)	77
			0	(390)	78
			0	(391)	79
			192,433	(392)	80
			0	(393)	81
			0	(394)	82
			0	(395)	83
			35,726	(396)	84
			691,266	(397)	85
			0	(398)	86
0	0	0	919,425		87
			0	(399)	88
			0	(399.1)	89
0	0	0	919,425		90
5,239,793	0	0	496,584,956		91
			0	(102)	92
			0		93
			0	(103)	94
5,239,793	0	0	496,584,956		95

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	April 18, 2008	Dec. 31, 2007

ELECTRIC OPERATING REVENUES (Account 400)

1. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
2. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
3. If previous year (columns (c), (e), and (g), are not derived from previously reported figures, explain any inconsistencies in a footnote.

Line No.	Title of Account (a)	OPERATING REVENUES Amount for Year (b)	Amount for Previous Year (c)
1	Sales of Electricity		
2	(440) Residential Sales	6,818	7,147
3	(442) Commercial and Industrial Sales (3)		
4	Small (or Commercial)	2,152	2,223
5	Large (or Industrial)		
6	(444) Public Street and Highway Lighting		
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	7,665	7,445
10	TOTAL Sales to Ultimate Consumers	16,635 (1)	16,815
11	(447) Sales for Resale	14,751,319	14,598,612
12	TOTAL Sales of Electricity	14,767,954	14,615,427
13	(Less) (449.1) Provision for Rate Refunds		
14	TOTAL Revenues Net of Provision for Refunds	14,767,954	14,615,427
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues		
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	47,639	45,136
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	9,123	98,905
22	(456.1) Revenues from Transmission of Electricty of Others	21,036	
23			
24			
25			
26	TOTAL Other Operating Revenues	77,798	144,041
27	TOTAL Electric Operating Revenues	$14,845,752	$14,759,468

State of Montana

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Avista Corporation	(1) [X] An Original (2) [ ] A Resubmission	April 18, 2008	Dec. 31, 2007

ELECTRIC OPERATING REVENUES (Account 400) (Continued)

4. Commercial and Industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classifcation is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)

5. See page 108, Important Changes During Year, for important new territory added and important rate increases or decreases.

6. For lines 2, 4, 5, and 6, see page 304 for amounts relating to unbilled revenue by accounts.

7. Include unmetered sales. Provide details of such sales in a foonote.

MEGAWATT HOURS SOLD		AVG. NO. OF CUSTOMERS PER MONTH		
Amount for Year (d)	Amount for Previous Year (e)	Number for Year (f)	Number for Previous Year (g)	Line No.
				1
150	158	10	11	2
				3
33	34	1	1	4
				5
				6
				7
				8
122	115	8	7	9
305 (2)	307	19	19	10
207,094	275,659		5	11
207,399	275,966	19	24	12
				13
207,399	275,966	19	24	14

(1) Includes $(0) of unbilled revenues.

(2) Includes 0 MWH relating to unbilled revenues.

(3) Segregation of Commerical and Industrial made on basis of utilization of energy and not on size of account.

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Cor	(1) [X] An Original (2) [ ] A Resubmi	April 18, 2008	December 31, 2007

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Prior Year (c)
1	(1) POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	141,110	115,243
5	(501) Fuel	16,515,707	14,659,509
6	(502) Steam Expenses	1,301,489	1,205,731
7	(503) Steam from Other Sources	-	16,016
8	(Less) (504) Steam Transferred-Cr.	-	-
9	(505) Electric Expenses	41,532	11,407
10	(506) Miscellaneous Steam Power Expenses	1,606,237	1,357,913
11	(507) Rents	29,922	19,628
12	(509) Allowances	-	-
13	TOTAL Operation (Enter Total of Lines 4 thru 11)	19,635,998	17,385,447
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	438,221	354,380
16	(511) Maintenance of Structures	451,048	454,469
17	(512) Maintenance of Boiler Plant	4,557,363	4,432,308
18	(513) Maintenance of Electric Plant	679,784	444,902
19	(514) Maintenance of Miscellaneous Steam Plant	542,111	534,244
20	TOTAL Maintenance (Enter Total of Lines 14 thru 18)	6,668,527	6,220,303
21	TOTAL Power Production Expenses-Steam Plant (Enter Total of	26,304,525	23,605,750
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	-	-
25	(518) Fuel	-	-
26	(519) Coolants and Water	-	-
27	(520) Steam Expenses	-	-
28	(521) Steam from Other Sources	-	-
29	(Less) (522) Steam Transferred-Cr.	-	-
30	(523) Electric Expenses	-	-
31	(524) Miscellaneous Nuclear Power Expenses	-	-
32	(525) Rents	-	-
33	TOTAL Operation (Enter Total of liens 23 thru 31)	-	-
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	-	-
36	(529) Maintenance of Structures	-	-
37	(530) Maintenance of Reactor Plant Equipment	-	-
38	(531) Maintenance of Electric Plant	-	-
39	(532) Maintenance of Miscellaneous Nuclear Plant	-	-
40	TOTAL Maintenance (Enter Total of lines 34 thru 38)	-	-
41	TOTAL Power Production Expenses-Nuclear Power(Enter total c	-	-
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	86,126	93,170
45	(536) Water for Power	-	-
46	(537) Hydraulic Expenses	71,797	77,203
47	(538) Electric Expenses	927,900	981,051
48	(539) Miscellaneous Hydraulic Power Generation Expenses	147,929	184,514
49	(540) Rents	-	-
50	TOTAL Operation (Enter Total of lines 43 thru 48)	1,233,752	1,335,938

Name of Respondent	This Report Is:		Date of Report	Year of Report
	(1)	X An Original		
Avista Cor	(2)	A Resubmi	April 25, 2005	December 31, 2007

AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
50	C. Hydraulic Power Generation (Continued)		
51	Maintenance		
52	(541) Maintenance Supervision and Engineering	64,791	34,077
53	(542) Maintenance of Structures	147,358	54,805
54	(543) Maintenance of Reservoirs, Dams, and Waterways	46,805	33,812
55	(544) Maintenance of Electric Plant	810,852	1,041,970
56	(545) Maintenance of Miscellaneous Hydraulic Plant	39,805	261,831
57	TOTAL Maintenance (Enter Total of lines 52 thru 56)	1,109,611	1,426,495
58	TOTAL Power Production Expenses-Hydraulic Power (Enter total	2,343,364	2,762,433
59	D. Other Power Generation		
60	Operation		
61	(546) Operation Supervision and Engineering	-	-
62	(547) Fuel	-	-
63	(548) Generation Expenses	-	-
64	(549) Miscellaneous Other Power Generation Expenses	-	-
65	(550) Rents	-	-
66	TOTAL Operation (Enter Total of lines 61 thru 65)	-	-
67	Maintenance		
68	(551) Maintenance Supervision and Engineering	-	-
69	(552) Maintenance of Structures	-	-
70	(553) Maintenance of Generating and Electric Plant	-	-
71	(554) Maintenance of Miscellaneous Other Power Generation Plant	-	-
72	TOTAL Maintenance (Enter Total of lines 68 thru 71)	-	-
73	TOTAL Power Production Expenses-Other Power (Enter Total of	-	-
74	E. Other Power Supply Expenses		
75	(555) Purchased Power	-	-
76	(556) System Control and Load Dispatching	-	-
77	(557) Other Expenses	-	-
78	TOTAL Other Power Supply Expenses (Enter Total of lines 75 th	-	-
79	TOTAL Power Production Expenses (Enter Total of lines 20, 40, 5	28,647,888	26,368,183
80	2. TRANSMISSION EXPENSES		
81	Operation		
82	(560) Operation Supervision and Engineering	23,339	24,043
83	(561) Load Dispatching	23,377	18,667
84	(561.1) Load Dispatching Reliability	-	-
85	(561.2) Load Dispatching Monitor and Operate Transmission System	-	18,667
86	(561.3) Load Dispatching Transmission Service and Sched	-	-
87	(561.4) Scheduling Sysemt Control and Dispatch Services	-	-
88	(561.5) Reliability, Planning and Standards Development	-	-
89	(561.6) Transmission Service Studies	-	-
90	(561.7) Generation Interconnection Studies	-	-
91	(561.8) Reliability, Planning and Standards Development Services	-	-
92	(562) Station Expenses	2,494	1,689
93	(563) Overhead Line Expenses	44,435	57,507
94	(564) Underground Line Expenses	-	-
95	(565) Transmission of Electricity by Others	-	-
96	(566) Miscellaneous Transmission Expenses	-	-
97	(567) Rents	68,268	65,802
98	TOTAL Operation (Enter Total of lines 82 thru 89)	161,912	186,376
99	Maintenance		
100	(568) Maintenance Supervision and Engineering	24,151	29,192
101	(569) Maintenance of Structures	5,723	7,523
102	(570) Maintenance of Station Equipment	59,805	56,691
103	(571) Maintenance of Overhead Lines	331,248	345,778
104	(572) Maintenance of Underground Lines	-	-
105	(573) Maintenance of Miscellaneous Transmission Plant	-	-
106	TOTAL Maintenance (Enter Total of lines 92 thru 97)	420,928	439,184
107	TOTAL Transmission Expenses (Enter Total of lines 90 and 98)	582,840	625,560
108	3. DISTRIBUTION EXPENSES		
109	Operation		
110	(580) Operation Supervision and Engineering	-	-

Name of Respondent	This Report Is:			Date of Report	Year of Report
	(1)	X	An Original		
Avista Cor	(2)		A Resubmi	April 18, 2008	December 31, 2007

AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Current Year (b)	Amount for Prior Year (c)
103	3. DISTRIBUTION EXPENSES (Continued)		
104	(581) Load Dispatching	-	-
105	(582) Station Expenses	-	-
106	(583) Overhead Line Expenses	-	-
107	(584) Underground Line Expenses	-	-
108	(585) Street Lighting and Signal System Expenses	-	-
109	(586) Meter Expenses	-	-
110	(587) Customer Installations Expenses	-	-
111	(588) Miscellaneous Distribution Expenses	-	-
112	(589) Rents	-	-
113	TOTAL Operation (Enter Total of lines 102 thru 112)	-	-
114	Maintenance		
115	(590) Maintenance Supervision and Engineering	-	-
116	(591) Maintenance of Structures	-	-
117	(592) Maintenance of Station Equipment	-	-
118	(593) Maintenance of Overhead Lines	-	-
119	(594) Maintenance of Underground Lines	-	-
120	(595) Maintenance of Line Transformers	-	-
121	(596) Maintenance of Street Lighting and Signal Systems	-	-
122	(597) Maintenance of Meters	-	-
123	(598) Maintenance of Miscellaneous Distribution Plant	-	-
124	TOTAL Maintenance (Enter Total of lines 115 thru 123)	-	-
125	TOTAL Distribution Expenses (Enter Total of lines 113 and 124)	-	-
126	4. CUSTOMER ACCOUNTS EXPENSES		
127	Operation		
128	(901) Supervision	-	-
129	(902) Meter Reading Expenses	-	-
130	(903) Customer Records and Collection Expenses	-	-
131	(904) Uncollectible Accounts	-	-
132	(905) Miscellaneous Customer Accounts Expenses	-	-
133	TOTAL Customer Accounts Expenses (Enter Total of lines 128 th	-	-
134	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
135	Operation		
136	(907) Supervision	-	-
137	(908) Customer Assistance Expenses	-	-
138	(909) Informational and Instructional Expenses	-	-
139	(910) Miscellaneous Customer Service and Informational Expenses	-	-
140	TOTAL Cust. Service and Informational Expenses (Enter Total of	-	-
141	6. SALES EXPENSES		
142	Operation		
143	(911) Supervision	-	-
144	(912) Demonstrating and Selling Expenses	-	-
145	(913) Advertising Expenses	-	-
146	(916) Miscellaneous Sales Expenses	-	-
147	TOTAL Sales Expenses (Enter Total of lines 143 thru 146)	-	-
148	7. ADMINISTRATIVE AND GENERAL EXPENSES		
149	Operation		
150	(920) Administrative and General Salaries	-	-
151	(921) Office Supplies and Expenses	-	-
152	(Less) (922) Administrative expenses Transferred-Credit	-	-

Name of Respondent	This Report Is:			Date of Report	Year of Report
	(1)	X	An Original		
Avista Cor	(2)		A Resubmi	April 18, 2008	December 31, 2007

AND MAINTENANCE EXPENSES

Line No.	Account (a)	Amount for Current Year (b)	Amount for Prior Year (c)
153	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
154	(923) Outside Services Employed	-	-
155	(924) Property Insurance	-	-
156	(925) Injuries and Damages	-	-
157	(926) Employee Pensions and Benefits	-	-
158	(927) Franchise Requirements	-	-
159	(928) Regulatory Commission Expenses	-	228
160	(Less) (929) Duplicate Charges-Cr.	-	-
161	(930.1) General Advertising Expenses	-	-
162	(930.2) Miscellaneous General Expenses	-	-
163	(931) Rents	-	-
164	TOTAL Operation (Enter Total of lines 150 thru 163)	-	228
165	Maintenance		
166	(935) Maintenance of General Plant	17,556	9,760
167	TOTAL Administrative and General Expenses (Enter Total of line	17,556	9,988
168	TOTAL Electric Operation and Maintenance Expenses (Enter Tot	29,248,284	27,003,731
	79,99,125,133,140,147,and 167)		

NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES

1. The data on number of empl construction employees in a footnote.
for the payroll period ending neare 3. The number of employees assignable to the electric
payroll period ending 60 days befo department from joint functions of combination utilities may
2. If the respondent's payroll for be determined by estimate, on the basis of employee equiva-
cludes any special construction lents. Show the estimated number of equivalent employees
employees on line 3, and show th attributed to the electric department from joint functions.

1 Payroll Period Ended (Date) December 31, 2007		
2 Total Regular Full-Time Employees	25	30
3 Total Part-Time and Temporary Employees	2	-
4 Allocation of General Employees	-	-
5 Total Employees (See Note 1)	27	30

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NOT DIRECTLY ASSIGNED TO STATES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
4 Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission		December 31, 2007

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.

2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Accounts 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified - Electric.

3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.

4. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.

5. Classify Account106 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 of unclassified retirements. Attach supplemental statement showing the account distributions of these tentative classifications in columns (c) and (d), including the

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	0	
3	(302) Franchises and Consents	0	
4	(303) Miscellaneous Intangible Plant	4,127,637	764,182
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	4,127,637	764,182
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	0	
9	(311) Structures and Improvements	0	
10	(312) Boiler Plant Equipment	0	
11	(313) Engines and Engine Driven Generators	0	
12	(314) Turbogenerator Units	0	
13	(315) Accessory Electric Equipment	0	
14	(316) Misc. Power Plant Equipment	0	
15	(317) Asset Retirement Costs for Steam Production	0	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	0	0
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	0	
19	(321) Structures and Improvements	0	
20	(322) Reactor Plant Equipment	0	
21	(323) Turbogenerator Units	0	
22	(324) Accessory Electric Equipment	0	
23	(325) Misc. Power Plant Equipment	0	
24	(326) Asset Retirement Costs for Nuclear Production	0	
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	0	0
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	0	
28	(331) Structures and Improvements	0	
29	(332) Reservoirs, Dams, and Waterways	0	
30	(333) Water Wheels, Turbines, and Generators	0	
31	(334) Accessory Electric Equipment	0	
32	(335) Misc. Power Plant Equipment	0	
33	(336) Roads, Railroads, and Bridges	0	
34	(337) Asset Retirement Costs for Hydraulic Production	0	
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	0	0
36	D. Other Production Plant		
37	(340) Land and Land Rights	0	
38	(341) Structures and Improvements	0	0
39	(342) Fuel Holders, Products and Accessories	0	
40	(343) Prime Movers	0	
41	(344) Generators	0	0
42	(345) Accessory Electric Equipment	0	

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2007

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

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

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, acquistion adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

7. For Account 399, state the nature and use of plant included in the 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 also date of such filing.

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			0	(301)	2
			0	(302)	3
1,955,108			2,936,711	(303)	4
1,955,108	0	0	2,936,711		5
					6
					7
			0	(310)	8
			0	(311)	9
			0	(312)	10
			0	(313)	11
			0	(314)	12
			0	(315)	13
			0	(316)	14
			0	(317)	15
0	0	0	0		16
					17
			0	(320)	18
			0	(321)	19
			0	(322)	20
			0	(323)	21
			0	(324)	22
			0	(325)	23
			0	(326)	24
0	0	0	0		25
					26
			0	(330)	27
			0	(331)	28
			0	(332)	29
			0	(333)	30
			0	(334)	31
			0	(335)	32
			0	(336)	33
			0	(337)	34
0	0	0	0		35
					36
			0	(340)	37
			0	(341)	38
			0	(342)	39
			0	(343)	40
			0	(344)	41
			0	(345)	42

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2007

ELECTRIC PLANT IN SERVICE (Accounts 101, 102, 103, 106)

Line No.	Account *(a)*		Balance at Beginning of Year *(b)*	Additions *(c)*
43	(346)	Misc. Power Plant Equipment	0	0
44	(347)	Asset Retirement Costs for Other Production	0	0
45		TOTAL Other Production Plant (Enter Total of lines 37 thru 44)	0	0
46		TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 45)	0	0
47		3. TRANSMISSION PLANT		
48	(350)	Land and Land Rights	0	
49	(352)	Structures and Improvements	0	
50	(353)	Station Equipment	0	0
51	(354)	Towers and Fixtures	0	
52	(355)	Poles and Fixtures	0	
53	(356)	Overhead Conductors and Devices	0	
54	(357)	Underground Conduit	0	
55	(358)	Underground Conductors and Devices	0	
56	(359)	Roads and Trails	0	
57	(359.1)	Asset Retirement Costs for Transmission Plant	0	
58		TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	0	0
59		4. DISTRIBUTION PLANT		
60	(360)	Land and Land Rights	0	
61	(361)	Structures and Improvements	0	
62	(362)	Station Equipment	0	
63	(363)	Storage Battery Equipment	0	
64	(364)	Poles, Towers, and Fixtures	0	
65	(365)	Overhead Conductors and Devices	0	
66	(366)	Underground Conduit	0	
67	(367)	Underground Conductors and Devices	0	
68	(368)	Line Transformers	0	
69	(369)	Services	0	
70	(370)	Meters	0	
71	(371)	Installations on Customer Premises	0	
72	(372)	Leased Property on Customer Premises	0	
73	(373)	Street Lighting and Signal Systems	0	
74	(374)	Asset Retirement Costs for Distribution Plant	129,707	0
75		TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	129,707	0
76		5. GENERAL PLANT		
77	(389)	Land and Land Rights	22,774	
78	(390)	Structures and Improvements	598,452	
79	(391)	Office Furniture and Equipment	136,601	377,275
80	(392)	Transportation Equipment	3,602,027	157,716
81	(393)	Stores Equipment	68,469	180,227
82	(394)	Tools, Shop and Garage Equipment	1,464,633	138,739
83	(395)	Laboratory Equipment	2,366,065	35,970
84	(396)	Power Operated Equipment	4,672,522	127,362
85	(397)	Communication Equipment	21,556,059	980,623
86	(398)	Miscellaneous Equipment	1,188	
87		SUBTOTAL (Enter Total of lines 77 thru 86)	34,488,790	1,997,912
88	(399)	Other Tangible Property	0	
89	(399.1)	Asset Retirement Costs for General Plant	0	
90		TOTAL General Plant (Enter Total of lines 87 thru 89)	34,488,790	1,997,912
91		TOTAL (Accounts 101 and 106)	38,746,135	2,762,094
92	(102)	Electric Plant Purchased	0	
93	(Less)	(102) Electric Plant Sold	0	
94	(103)	Experimental Plant Unclassified	0	
95		TOTAL Electric Plant in Service	38,746,135	2,762,094

Not Directly Assigned To States

Name of Respondent	This Report Is:	Date of Report	Year of Report
Avista Corp.	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	December 31, 2007

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
			0	(346)	43
			0	(347)	44
0	0	0	0		45
0	0	0	0		46
					47
			0	(350)	48
			0	(352)	49
0			0	(353)	50
			0	(354)	51
			0	(355)	52
			0	(356)	53
			0	(357)	54
			0	(358)	55
			0	(359)	56
			0	(359.1)	57
0	0	0	0		58
					59
			0	(360)	60
			0	(361)	61
			0	(362)	62
			0	(363)	63
			0	(364)	64
			0	(365)	65
			0	(366)	66
			0	(367)	67
			0	(368)	68
			0	(369)	69
			0	(370)	70
			0	(371)	71
			0	(372)	72
			0	(373)	73
			129,707	(374)	74
0	0	0	129,707		75
					76
			22,774	(389)	77
			598,452	(390)	78
0			513,876	(391)	79
366,923			3,392,820	(392)	80
			248,696	(393)	81
17,518			1,585,854	(394)	82
5,702			2,396,333	(395)	83
			4,799,884	(396)	84
70,439		0	22,466,243	(397)	85
85			1,103	(398)	86
460,667	0	0	36,026,035		87
			0	(399)	88
			0	(399.1)	89
460,667	0	0	36,026,035		90
2,415,775	0	0	39,092,453		91
			0	(102)	92
			0		93
			0	(103)	94
2,415,775	0	0	39,092,453		95

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