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

Form 1 Approved
OMB No. 1902-0021
(Expires 2/29/2009)
Form 1-F Approved
OMB No. 1902-0029
(Expires 2/28/2009)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 2/28/2009)

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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
Idaho Power Company	End of 2008/Q4

Deloitte.

Deloitte & Touche LLP
Suite 1700
101 South Capitol Boulevard
Boise, ID 83702-7734
USA

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INDEPENDENT AUDITORS' REPORT

Idaho Power Company
Boise, Idaho

We have audited the balance sheet — regulatory basis of Idaho Power Company (the "Company") as of December 31, 2008, and the related statements of income — regulatory basis; retained earnings — regulatory basis; cash flows — regulatory basis, and accumulated other comprehensive income, comprehensive income, and hedging activities — regulatory basis, for the year ended December 31, 2008, included on pages 110 through 123 of the accompanying Federal Energy Regulatory Commission Form 1. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

As discussed in Note 1, these financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America.

In our opinion, such regulatory-basis financial statements present fairly, in all material respects, the assets, liabilities, and proprietary capital of the Company as of December 31, 2008, and the results of its operations and its cash flows for the year ended December 31, 2008, in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

This report is intended solely for the information and use of the board of directors and management of the Company and for filing with the Federal Energy Regulatory Commission and is not intended to be and should not be used by anyone other than these specified parties.

Deloitte + Touche LLP

February 25, 2009

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

IDENTIFICATION

01 Exact Legal Name of Respondent Idaho Power Company	02 Year/Period of Report End of 2008/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)* 1221 W Idaho Street, P.O. Box 70 Boise, Id 83707-0070	
05 Name of Contact Person Darrel Anderson	06 Title of Contact Person Senior VP of Admin Ser & CFO
07 Address of Contact Person *(Street, City, State, Zip Code)* 1221 W Idaho Street, P.O. Box 70 Boise, Id 83707-0070	

08 Telephone of Contact Person, *Including Area Code* (208) 388-2650	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* 04/15/2009

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 Darrel Anderson	03 Signature Darrel Anderson	04 Date Signed *(Mo, Da, Yr)* 04/15/2009
02 Title Senior VP of Admin Ser & CFO		

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
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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	
3	Corporations Controlled by Respondent	103	
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5	Directors	105	
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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	None
15	Electric Plant in Service	204-207	
16	Electric Plant Leased to Others	213	None
17	Electric Plant Held for Future Use	214	
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	None
23	Extraordinary Property Losses	230	
24	Unrecovered Plant and Regulatory Study Costs	230	
25	Transmission Service and Generation Interconnection Study Costs	231	None
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	
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	

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	
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	None
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	
53	Distribution of Salaries and Wages	354-355	
54	Common Utility Plant and Expenses	356	None
55	Amounts included in ISO/RTO Settlement Statements	397	None
56	Purchase and Sale of Ancillary Services	398	None
57	Monthly Transmission System Peak Load	400	
58	Monthly ISO/RTO Transmission System Peak Load	400a	None
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	
64	Generating Plant Statistics Pages	410-411	
65	Transmission Line Statistics Pages	422-423	
66	Transmission Lines Added During the Year	424-425	

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
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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.

Darrel Anderson Senior Vice President of Administrative Services and CFO, Idaho Power Company
1221 W. Idaho Street, P.O. Box 70, Boise, Idaho 83707-0070

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.

Idaho, June 30, 1989

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.

Class of Utility Service	State
Electric	Idaho
"	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 Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report *(Mo, Da, Yr)* 04/15/2009	Year/Period of Report End of 2008/Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiearies for whom trust was maintained, and purpose of the trust.

Idaho Power Company is a subsidiary of IDACORP, INC

IDACORP owns 100% of Idaho Power Company's Common Stock.

IDACORP is a public utility Holding Company incorporated effective 10-1-1998

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/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	Direct Control			
2	Idaho Energy Resources Company	Coal mining and mineral	100%	
3		development		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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			
2	President and Chief Executive Officer	J. LaMont Keen	600,000
3			
4	Sr Vice President, Administrative Services & CFO	Darrel T. Anderson	340,000
5			
6	Sr Vice President, Power Supply	James C. Miller	300,000
7			
8	Sr Vice President, General Counsel and Secretary	Thomas Saldin	300,000
9			
10	Sr Vice President, Delivery	Dan Minor	290,000
11			
12	Vice President, Regulatory Affairs	Ric Gale	230,000
13			
14	Vice President and Chief Information Officer	Dennis Gribble	198,000
15			
16	Vice President, Human Resources	Luci McDonald	205,000
17			
18	Vice President, Public Affairs (1)	Greg Panter	170,833
19			
20	Vice President and Treasurer	Steven R. Keen	215,000
21			
22	Vice President and Chief Risk Officer	Lori Smith	194,000
23			
24	Vice President, Engineering and Operations	Lisa Grow	180,000
25			
26	Vice President Public Affairs (2)	Jeffrey Malmen	30,000
27			
28	Vice President, Customer Service and Regional Ops	Warren Kline	177,500
29			
30	Vice President, Audit and Compliance	Naomi Crafton-Shankel	154,000
31			
32	Corporate Secretary	Patrick Harrington	155,000
33			
34			
35	(1) Retired 9/30/2008		
36	(2) Appointed Vice President Public Affairs 10/1/08		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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		
2	Judith A Johansen	2786 Glenmorrie Dr. Lake Oswego, Oregon 97034
3		
4	Christine King	Standard Microsystems Corporation
5		80 Arkay Dr, Hauppauge, NY 11788
6		
7	Gary Michael ***	P.O. Box 1718, Boise, Idaho 83701
8		
9	Jon H. Miller ***	P.O. Box 1557, Boise, Idaho 83701
10		
11	Peter S. O'Neill ***	100 N. 9th St., Suite 200, Boise, Idaho 83702
12		
13	Jan B. Packwood	900 W. Bogus View Drive, Eagle, Idaho 83616
14		
15	J. LaMont Keen, President and Chief Executive Officer**	Idaho Power Company, 1221 W. Idaho Street,
16		P.O. Box 70, Boise, Idaho 83707-0070
17		
18	Richard G. Reiten	Pacwest Center, 1211 SW Fifth Ave., Suite 1600
19		Portland, Oregon 97204
20		
21	Joan Smith	2309 S.W. First Avenue, No. 1141, Portland, Oregon 97201
22		
23	Robert A. Tinstman ***	4433 W. Quail Point Court, Boise, Idaho 83703
24		
25	Thomas Wilford	Alscott Inc, P.O. Box 70001, Boise, Idaho 83701
26		
27	Richard Dahl	11659 Presilla Road, Santa Rosa Valley Ca, 93012
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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. There was a retirement of $60,000 of the old Shoshone Bannock distribution right of way, that was fully amortized.

2. None

3. None

4. None

5. Additions to Existing Lines:
Tap added to transmission line 213 to Adroam 69Kv 5.6 miles added.

Upgrade transmission lines from 69kv to 138 kv:
Line 473 138Kv 11.73 miles, replaces line 203 69Kv
Line 470 138Kv 24.19 miles, replaces line 236 69Kv

Distribution Stations:
Poleline Substation
Hillsdale Substation

6. On July 10, 2008, IPC issued $120 million of its 6.025% First Mortgage Bonds Secured Medium-Term Notes, Series H due July 15, 2018. Commission Authorization OPUC 08-105 IPUC #3048.

On April 3, 2008 entered into a Selling Agency Agreement (see page 123.9) Commission Authorization OPUC 07-151 IPUC #30294.

7. None

8.On December 31, 2008 a general wage increase of 3%.

9. See Pages 123.17 to 123.22

10. None

11. None

12. None

13. Refer to pages 104 & 105 for changes in officers and directors. There were a number of changes in Major Security holders in 2008. The top ten institutional shareholders list saw two changes from 3rd quarter to 4th quarter. In the 4th quarter Deutche Investment Management Americas and Integrity Asset Management LLC, replaced Lord Abbett & Co LLC and Dimensional Fund Advisors, Inc.

14.Idaho Pwer and its unregulated parent. IDACORP have seperate cash management programs. (Seperate bank accounts, liquidity facilities, short-term debt and investment programs). No money has been loaned or advanced from Idaho Power to IDACORP through a cash management program.

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Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	4,036,452,062	3,799,704,789
3	Construction Work in Progress (107)	200-201	207,662,162	257,589,900
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		4,244,114,224	4,057,294,689
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	1,505,119,564	1,468,831,767
6	Net Utility Plant (Enter Total of line 4 less 5)		2,738,994,660	2,588,462,922
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)		2,738,994,660	2,588,462,922
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)		786,896	888,877
19	(Less) Accum. Prov. for Depr. and Amort. (122)		0	0
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	60,058,187	55,937,107
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)		948,473	4,846
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		19,129,856	28,071,728
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	33,160
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		80,923,412	84,935,718
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		2,819,926	2,908,319
36	Special Deposits (132-134)		675,912	44,840,534
37	Working Fund (135)		41,350	35,850
38	Temporary Cash Investments (136)		280,000	2,403,000
39	Notes Receivable (141)		1,549,041	5,975,468
40	Customer Accounts Receivable (142)		64,433,173	62,122,209
41	Other Accounts Receivable (143)		6,557,937	7,080,171
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		1,723,936	1,305,058
43	Notes Receivable from Associated Companies (145)		26,579,771	21,527,626
44	Accounts Receivable from Assoc. Companies (146)		-2,011	0
45	Fuel Stock (151)	227	16,851,868	17,267,629
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	44,405,727	41,370,751
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

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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	5,715,442	1,898,952
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		9,865,355	9,119,846
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	611
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		43,933,916	36,314,344
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		652,080	586,202
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	33,160
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)		222,635,551	252,113,294
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		14,263,910	13,390,497
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	697,644,724	448,227,917
73	Prelim. Survey and Investigation Charges (Electric) (183)		7,232,442	454,153
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		486,154	480,898
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	63,059,804	73,222,183
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	36,000
81	Unamortized Loss on Reaquired Debt (189)		12,841,023	13,548,821
82	Accumulated Deferred Income Taxes (190)	234	167,646,855	106,047,150
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		963,174,912	655,407,619
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		4,005,728,535	3,580,919,553

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Rresubmission	04/15/2009	end of 2008/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	97,877,030	97,877,030
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	618,757,435	581,757,435
7	Other Paid-In Capital (208-211)	253	0	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	2,096,925	2,096,925
11	Retained Earnings (215, 215.1, 216)	118-119	424,451,953	388,826,291
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	57,595,094	53,474,014
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)	-8,706,615	-6,156,499
16	Total Proprietary Capital (lines 2 through 15)		1,187,877,972	1,113,681,346
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,401,560,000	1,115,460,000
19	(Less) Reaquired Bonds (222)	256-257	166,100,000	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	29,457,727	30,521,364
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		3,163,279	3,409,345
24	Total Long-Term Debt (lines 18 through 23)		1,261,754,448	1,142,572,019
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		1,965,108	660,554
29	Accumulated Provision for Pensions and Benefits (228.3)		253,645,884	81,470,279
30	Accumulated Miscellaneous Operating Provisions (228.4)		916,667	916,667
31	Accumulated Provision for Rate Refunds (229)		13,344,853	2,397,165
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		12,414,695	14,514,992
35	Total Other Noncurrent Liabilities (lines 26 through 34)		282,287,207	99,959,657
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		112,850,000	136,585,000
38	Accounts Payable (232)		94,937,929	81,922,232
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		765,831	724,321
41	Customer Deposits (235)		311,092	1,159,231
42	Taxes Accrued (236)	262-263	-42,412,650	2,845,258
43	Interest Accrued (237)		16,674,614	18,761,346
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Rresubmission	04/15/2009	end of 2008/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		1,329,837	2,534,420
48	Miscellaneous Current and Accrued Liabilities (242)		37,600,238	59,832,828
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		2,652,850	171,234
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		224,709,741	304,535,870
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		30,033,657	33,261,676
57	Accumulated Deferred Investment Tax Credits (255)	266-267	73,270,077	71,000,710
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	29,939,135	20,838,443
60	Other Regulatory Liabilities (254)	278	203,648,107	203,756,794
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		580,306,037	535,627,552
64	Accum. Deferred Income Taxes-Other (283)		131,902,154	55,685,486
65	Total Deferred Credits (lines 56 through 64)		1,049,099,167	920,170,661
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		4,005,728,535	3,580,919,553

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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	956,075,564	875,401,235		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	581,177,704	532,394,837		
5	Maintenance Expenses (402)	320-323	68,638,630	68,163,077		
6	Depreciation Expense (403)	336-337	96,637,583	94,999,200		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	5,482,388	8,095,753		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	-22,723	-22,723		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)			21,246		
13	(Less) Regulatory Credits (407.4)		3,781,013	-2,093,195		
14	Taxes Other Than Income Taxes (408.1)	262-263	19,083,954	17,633,417		
15	Income Taxes - Federal (409.1)	262-263	-1,816,783	2,627,990		
16	- Other (409.1)	262-263	-4,930,646	-6,572,551		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	111,854,164	44,230,688		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	71,534,676	9,243,213		
19	Investment Tax Credit Adj. - Net (411.4)	266	2,269,367	1,887,569		
20	(Less) Gains from Disp. of Utility Plant (411.6)		11,632			
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		504,115	2,754,122		
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)		802,542,202	753,554,363		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		153,533,362	121,846,872		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

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

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
956,075,564	875,401,235					2
						3
581,177,704	532,394,837					4
68,638,630	68,163,077					5
96,637,583	94,999,200					6
						7
5,482,388	8,095,753					8
-22,723	-22,723					9
						10
						11
	21,246					12
3,781,013	-2,093,195					13
19,083,954	17,633,417					14
-1,816,783	2,627,990					15
-4,930,646	-6,572,551					16
111,854,164	44,230,688					17
71,534,676	9,243,213					18
2,269,367	1,887,569					19
11,632						20
						21
504,115	2,754,122					22
						23
						24
802,542,202	753,554,363					25
153,533,362	121,846,872					26

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/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)		153,533,362	121,846,872		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		1,523,301	2,706,144		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		1,253,357	2,066,935		
33	Revenues From Nonutility Operations (417)		75,270	102,798		
34	(Less) Expenses of Nonutility Operations (417.1)		-1,567,569	-515,189		
35	Nonoperating Rental Income (418)		-14,913	-2,553		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	4,121,080	4,022,911		
37	Interest and Dividend Income (419)		3,894,223	3,819,829		
38	Allowance for Other Funds Used During Construction (419.1)		3,141,017	5,995,175		
39	Miscellaneous Nonoperating Income (421)		608,609	6,514,689		
40	Gain on Disposition of Property (421.1)		3,051,506	321,364		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		16,714,305	21,928,611		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)	340				
45	Donations (426.1)	340	405,900	478,611		
46	Life Insurance (426.2)		-381,000	-200,209		
47	Penalties (426.3)		426,409	919,811		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,273,313	886,146		
49	Other Deductions (426.5)		4,817,233	4,528,201		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		6,541,855	6,612,560		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	31,465	35,980		
53	Income Taxes-Federal (409.2)	262-263	3,078,590	1,749,032		
54	Income Taxes-Other (409.2)	262-263	615,804	370,373		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	1,203,011	1,552,871		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	4,822,172	1,905,495		
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)		106,698	1,802,761		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		10,065,752	13,513,290		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		66,145,498	58,097,083		
63	Amort. of Debt Disc. and Expense (428)		1,099,817	1,081,816		
64	Amortization of Loss on Reaquired Debt (428.1)		707,798	1,211,833		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)	340				
68	Other Interest Expense (431)	340	8,611,213	5,987,546		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		7,080,140	7,597,141		
70	Net Interest Charges (Total of lines 62 thru 69)		69,484,186	58,781,137		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		94,114,928	76,579,025		
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)		94,114,928	76,579,025		

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Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		387,282,325	353,080,906
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	FIN 48 Adjustment			15,135,588
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			15,135,588
16	Balance Transferred from Income (Account 433 less Account 418.1)		89,993,848	72,556,114
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	Common Stock Dividends $2.50 Par Value	238	-54,368,186	(53,490,283)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-54,368,186	(53,490,283)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		422,907,987	387,282,325

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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				
40				
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		1,543,966	1,543,966
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		1,543,966	1,543,966
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		424,451,953	388,826,291
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		53,474,014	49,451,103
50	Equity in Earnings for Year (Credit) (Account 418.1)		4,121,080	4,022,911
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)		57,595,094	53,474,014

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)	94,114,928	76,579,025
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	96,637,583	94,999,200
5	Amortization of	12,409,124	12,500,338
6			
7			
8	Deferred Income Taxes (Net)	24,923,640	35,380,117
9	Investment Tax Credit Adjustment (Net)	1,373,356	1,142,301
10	Net (Increase) Decrease in Receivables	-1,930,182	-12,548,004
11	Net (Increase) Decrease in Inventory	-6,435,706	-6,285,284
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-28,488,583	-7,717,708
14	Net (Increase) Decrease in Other Regulatory Assets	-60,996,430	-105,234,939
15	Net Increase (Decrease) in Other Regulatory Liabilities	-3,071,792	-22,854,309
16	(Less) Allowance for Other Funds Used During Construction	3,141,017	5,995,175
17	(Less) Undistributed Earnings from Subsidiary Companies	4,121,080	4,022,911
18	Other (provide details in footnote):	112,383	29,227,514
19			
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	121,386,224	85,170,165
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-236,464,054	-279,621,563
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	7,080,140	7,597,141
31	Other (provide details in footnote): Sale of Emission Allowances	2,958,500	19,845,542
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-240,585,694	-267,373,162
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	5,784,800	525,994
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		-12,373,146
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		-24,348,700
45	Proceeds from Sales of Investment Securities (a)	4,100,665	26,110,459

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables	-7,449,788	-789,874
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	Tax deposit withdrawal	43,926,946	-43,926,946
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-194,223,071	-322,175,375
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	290,000,000	240,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		84,385,000
67	Other (provide details in footnote): Capital Infusion	37,000,000	51,000,000
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	327,000,000	375,385,000
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-167,163,636	-81,063,636
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):	-2,150,077	-883,004
77			
78	Net Decrease in Short-Term Debt (c)	-32,687,145	
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-54,368,186	-53,490,283
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	70,630,956	239,948,077
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-2,205,891	2,942,867
87			
88	Cash and Cash Equivalents at Beginning of Period	5,347,167	2,404,300
89			
90	Cash and Cash Equivalents at End of period	3,141,276	5,347,167

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Schedule Page: 120 Line No.: 5 Column: b

Note 1	Amortization	Year Ended 12/31/08
	Plant	5,459,665
	Regulatory assets	3,706,837
	Unamortized debt expense	(172,725)
	Unamortized discount	246,065
	Water rights	3,169,282
		12,409,124

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

Note 2	Cash Flow from Operating Activities (Other)	Year Ended 12/31/08
	Non-cash pension expense	3,512,857
	Gain on sale of emission allowances	(504,115)
	Loss on liquidation of money market	156,030
	Gain on sale of non-utility property	(3,112,406)
	Unbilled revenues	(7,619,571)
	Impairment of security plan assets	6,829,456
	Other noncash adjustments to net income	1,000,000
	Other current liabilities	(6,130,315)
	Other long-term assets	1,491,800
	Other long-term liabilities	4,488,647
		112,383

NOTES TO FINANCIAL STATEMENTS

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

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SEE PAGE 123 FOR REQUIRED INFORMATION.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Idaho Power Company (IPC) a wholly-owned subsidiary of IDACORP, Inc., (IDACORP) is an electric utility with a service territory covering approximately 24,000 square miles in southern Idaho and eastern Oregon. IPC is regulated by the FERC and the state regulatory commissions of Idaho and Oregon. IPC is the parent of Idaho Energy Resources Co. (IERCo), a joint venturer in Bridger Coal Company, which supplies coal to the Jim Bridger generating plant owned in part by IPC.

Management Estimates
Management makes estimates and assumptions when preparing financial statements in conformity with accounting principles generally accepted in the United States of America. These estimates and assumptions include those related to rate regulation, retirement benefits, contingencies, litigation, asset impairment, income taxes, unbilled revenues and bad debt. These estimates and assumptions affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. These estimates involve judgments with respect to, among other things, future economic factors that are difficult to predict and are beyond management's control. As a result, actual results could differ from those estimates.

System of Accounts
The accounting records of IPC conform to the Uniform System of Accounts prescribed by the FERC and adopted by the public utility commissions of Idaho, Oregon and Wyoming.

Regulation of Utility Operations
IPC follows Statement of Financial Accounting Standards (SFAS) 71, *Accounting for the Effects of Certain Types of Regulation,* and its financial statements reflect the effects of the different ratemaking principles followed by the jurisdictions regulating IPC. The application of SFAS 71 sometimes results in IPC recording expenses in a different period than when an unregulated enterprise would record the expenses. In these circumstances, the expenses are deferred as regulatory assets on the balance sheet and recorded on the income statement when recovered in rates. Additionally, regulators can impose regulatory liabilities upon a regulated company for amounts previously collected from customers and for amounts that are expected to be refunded to customers. The effects of applying SFAS 71 are discussed in more detail in Note 6.

Cash and Cash Equivalents
Cash and cash equivalents include cash on hand and highly liquid temporary investments with maturity dates at date of acquisition of three months or less.

Derivative Financial Instruments
Financial instruments such as commodity futures, forwards, options and swaps are used to manage exposure to commodity price risk in the electricity market. The objective of the risk management program is to mitigate the risk associated with the purchase and sale of electricity and natural gas. The accounting for derivative financial instruments that are used to manage risk is in accordance with the concepts established by SFAS 133, *Accounting for Derivative Instruments and Hedging Activities,* as amended.

Property, Plant and Equipment and Depreciation
The cost of utility plant in service represents the original cost of contracted services, direct labor and material, Allowance for Funds Used During Construction (AFUDC) and indirect charges for engineering, supervision and similar overhead items. Repair and maintenance costs associated with planned major maintenance are expensed as the costs are incurred, as are maintenance and repairs of property and replacements and renewals of items determined to be less than units of property. For utility property replaced or renewed, the original cost plus removal cost less salvage is charged to accumulated provision for depreciation, while the cost of related replacements and renewals is added to property, plant and equipment.

All utility plant in service is depreciated using the straight-line method at rates approved by regulatory authorities. Annual depreciation provisions as a percent of average depreciable utility plant in service approximated 2.73 percent in 2008 and 2.95 percent in 2007.

Long-lived assets are periodically reviewed for impairment when events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable as prescribed under SFAS 144. SFAS 144 requires that if the sum of the undiscounted expected future cash flows from an asset is less than the carrying value of the asset, impairment must be recognized in the financial statements. There were no impairments of long-lived assets in 2008.

Allowance for Funds Used During Construction
AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. While cash is not realized currently from such allowance, it is realized under the rate-making process over the service life of the related property through increased revenues resulting from a higher rate base and higher depreciation expense. The component of AFUDC attributable to borrowed funds is included as a reduction to interest expense, while the equity component is included in other income. IPC's weighted-average monthly AFUDC rates for 2008 and 2007 were 5.2 percent and 6.8 percent, respectively. IPC's reductions to interest expense for AFUDC were $7 million for 2008 and $8 million for 2007. Other income included $3 million and $6 million of AFUDC for 2008 and 2007, respectively.

Revenues
Operating revenues for IPC related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. IPC accrues unbilled revenues for electric services delivered to customers but not yet billed at period-end. IPC collects franchise fees and similar taxes related to energy consumption. These amounts are recorded as liabilities until paid to the taxing authority. None of these collections are reported on the income statement as revenue or expense.

Income Taxes
IPC accounts for income taxes under the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Under this method, deferred tax assets and liabilities are determined based on the differences between the financial statements and tax basis of assets and liabilities using enacted tax rates in effect for the year in which the differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date.

Consistent with orders and directives of the Idaho Public Utilities Commission (IPUC), the regulatory authority having principal jurisdiction, IPC's deferred income taxes (commonly referred to as normalized accounting) are provided for the difference between income tax depreciation and straight-line depreciation computed using book lives on coal-fired generation facilities and properties acquired after 1980. On other facilities, deferred income taxes are provided for the difference between accelerated income tax depreciation and straight-line depreciation using tax guideline lives on assets acquired prior to 1981. Deferred income taxes are not provided for those income tax timing differences where the prescribed regulatory accounting methods do not provide for current recovery in rates. Regulated enterprises are required to recognize such adjustments as regulatory assets or liabilities if it is probable that such amounts will be recovered from or returned to customers in future rates.

The state of Idaho allows a three-percent investment tax credit on qualifying plant additions. Investment tax credits earned on regulated assets are deferred and amortized to income over the estimated service lives of the related properties. Credits earned on non-regulated assets or investments are recognized in the year earned.

Income taxes are discussed in more detail in Note 2.

Comprehensive Income
Comprehensive income includes net income, unrealized holding gains and losses on available-for-sale marketable securities and amounts related to a deferred compensation plan for certain senior management employees and directors called the Senior Management Security Plan (SMSP). The following table presents IPC's accumulated other comprehensive loss balance at December 31 (net of tax):

		2008		2007
		(thousands of dollars)		
Unrealized holding gains on available-for-sale securities	$	-	$	568
SMSP		(8,707)		(6,724)
Total	$	(8,707)	$	(6,156)

Other Accounting Policies
Debt discount, expense and premium are deferred and being amortized over the terms of the respective debt issues.

New Accounting Pronouncements
SFAS 141(R): In December 2007, the Financial Accounting Standards Board (FASB) issued SFAS 141(R), *Business Combinations (Revised December 2007)*. SFAS 141(R) establishes principles and requirements for how an acquirer in a business combination: (1) recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree; (2) recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase; and (3) determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. SFAS 141(R) applies prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. An entity may not apply it before that date. The adoption of SFAS 141(R) did not have a material impact on the consolidated financial statements of IPC.

SFAS 160: In December 2007, the FASB issued SFAS 160, *Noncontrolling Interests in Consolidated Financial Statements.* Among other things, SFAS 160 establishes a standard for the way noncontrolling interests (also called minority interests) are presented in consolidated financial statements and standards for accounting for changes in ownership interests. SFAS 160 is effective for fiscal years beginning on or after December 15, 2008. An entity may not apply it before that date. The adoption of SFAS 160 did not have a material impact on the consolidated financial statements of IPC.

SFAS 161: In March 2008, the FASB issued SFAS 161, *Disclosures about Derivative Instruments and Hedging Activities—an amendment of FASB Statement No. 133*. SFAS 161 encourages, but does not require, comparative disclosures for earlier periods at initial adoption. SFAS 161 changes the disclosure requirements for derivative instruments and hedging activities. Entities are required to provide enhanced disclosures about (1) how and why an entity uses derivative instruments, (2) how derivative instruments and related hedged items are accounted for under Statement 133 and its related interpretations, and (3) how derivative instruments and related hedged items affect an entity's financial position, financial performance, and cash flows. SFAS 161 is effective for financial statements issued for fiscal years and interim periods beginning after November 15, 2008, with early application encouraged. The adoption of SFAS 161 did not have a material impact on the consolidated financial statements of IPC.

SFAS 163: In May 2008, the FASB issued SFAS 163, *Accounting for Financial Guarantee Insurance Contracts—an interpretation of FASB Statement No. 60.* SFAS 163 is generally effective for financial statements issued for fiscal years beginning after December 15, 2008. SFAS 163 did not impact the consolidated financial statements of IPC.

FSP EITF 03-6-1: In June 2008, the FASB issued FSP EITF 03-6-1, *Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities*. Under the guidance in FSP EITF 03-6-1, unvested share-based payment awards that contain non-forfeitable rights to dividends or dividend equivalents (whether paid or unpaid) are participating securities and shall be included in the computation of earnings per share pursuant to the two-class method described in SFAS No. 128, *Earnings per Share.* FSP EITF 03-6-1 is effective for financial statements issued for fiscal years beginning after December 15, 2008. All prior-period earnings per share data presented must be adjusted retrospectively, and early application is not permitted. The adoption of EITF 03-6-1 did not have a material impact on the consolidated financial statements of IPC.

FSP FAS 142-3: In April 2008, the FASB issued FASB Staff Position (FSP) FAS 142-3, *Determination of the Useful Life of Intangible Assets.* FSP FAS 142-3 removes the requirement of SFAS 142, *Goodwill and Other Intangible Assets,* for an entity to consider, when determining the useful life of an acquired intangible asset, whether the intangible asset can be renewed without substantial cost or material modifications to the existing terms and conditions associated with the intangible asset. FSP FAS 142-3 replaces the previous useful-life assessment criteria with a requirement that an entity consider its own experience in renewing similar arrangements. If the entity has no relevant experience, it would consider market participant assumptions regarding renewal. FSP FAS 142-3 is effective for financial statements issued for fiscal years beginning after December 15, 2008. The adoption of FSP FAS 142-3 did not have a material impact on the consolidated financial statements of IPC.

2. INCOME TAXES:

The components of the net deferred tax liability are as follows:

	2008	2007
	(thousands of dollars)	
Deferred tax assets:		
Regulatory liabilities	$ 44,341	$ 42,968
Advances for construction	9,305	10,172
Deferred compensation	17,052	16,423
Emission allowances	-	6,921
Retirement benefits	85,034	20,753
Other	15,029	8,810
Total	170,761	106,047
Deferred tax liabilities:		
Property, plant and equipment	246,424	227,338
Regulatory assets	333,882	308,290
Conservation programs	1,901	3,169
PCA	62,820	45,008
Retirement benefits	69,334	6,945
Other	961	563
Total	715,322	591,313
Net deferred tax liabilities	$ 544,561	$ 485,266

A reconciliation between the statutory federal income tax rate and the effective tax rate is as follows:

	2008	2007
	(thousands of dollars)	
Computed income taxes based on statutory federal income tax rate	$ 45,511	$ 38,947
Change in taxes resulting from:		
Equity earnings of subsidiary companies	(1,442)	(1,408)
AFUDC	(3,577)	(4,757)
Capitalized interest	1,729	2,289
Investment tax credits	(3,490)	(3,578)
Repair allowance	(2,450)	(2,450)
Removal costs	(2,954)	(3,787)
Pension accrual	-	1,022
Capitalized overhead costs	(4,200)	(4,200)
Tax accounting method change	-	-
Uncertain tax positions	(13,475)	(3,346)
Settlement of prior years' tax returns	11,994	-
State income taxes, net of federal benefit	4,601	6,618
Depreciation	5,562	7,576
Other, net	(1,892)	1,771
Total income tax expense	$ 35,917	$ 34,697
Effective tax rate	27.6%	31.2%

The items comprising income tax expense are as follows:

	2008	2007

Income taxes currently payable:		
Federal	$ 14,024	$ 7,963
State	(3,602)	(6,202)
Total	10,422	1,761
Income taxes deferred:		
Federal	33,906	28,412
State	2,794	6,223
Total	36,700	34,635
Uncertain tax positions:		
Federal	(12,763)	(3,345)
State	(712)	(241)
Total	(13,475)	(3,586)
Investment tax credits:		
Deferred	5,760	5,465
Restored	(3,490)	(3,578)
Total	2,270	1,887
Total income tax expense	$ 35,917	$ 34,697

IDACORP's tax allocation agreement provides that each member of its consolidated group compute its income taxes on a separate company basis. Amounts payable or refundable are settled through IDACORP.

FIN 48

IPC adopted FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109* (FIN 48) on January 1, 2007, as required. IPC recorded an increase of $15.1 million to 2007 opening retained earnings for the cumulative effect of adopting FIN 48. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows (in thousands of dollars):

	2008	2007
Balance at January 1,	$ 17,594	$ 21,180
Additions for tax positions of prior years	1,280	848
Reductions for tax positions of prior years	(10,426)	(4,434)
Settlements with taxing authorities	(4,329)	-
Balance at December 31,	$ 4,119	$ 17,594

If recognized, the $4.1 million balance of unrecognized tax benefits would affect IPC's effective tax rates.

Since 2006, IPC has been disputing the Internal Revenue Service's (IRS) disallowance of IPC's use of the simplified service cost method (SSCM) of uniform capitalization for tax years 2001-2004. The dispute has been under review with the IRS Appeals Office. In December 2008, the Appeals Office informed IDACORP that the SSCM settlement computations were complete. IDACORP reviewed the final computations and agreed to the result. The settlement was submitted to the U.S. Congress Joint Committee on Taxation (JCT) for review in January 2009.

In November 2006, IDACORP made a $44.9 million refundable tax deposit with the IRS related to the disputed income tax assessment for SSCM. In May 2008, IDACORP withdrew $20 million from the deposit. Approximately $21 million from the deposit was applied to the settled income tax deficiency and interest charges with the remaining balance refunded to IDACORP.

The IRS completed its examination of IDACORP's 2004 tax year in August 2008 and its 2005 tax year in October 2008. The 2004 examination report was submitted for JCT review as part of the SSCM settlement and the 2005 report was submitted in November 2008. IDACORP expects the JCT review process for 2001-2005 to be completed in 2009. As of December 31, 2008, all uncertain tax positions related to tax years 2001-2005 were considered effectively settled.

The IRS began examining IPC's current method of uniform capitalization in December 2008. IDACORP expects that the examination will be completed during 2009. Resolution would result in a decrease to IPC's unrecognized tax benefits of $4.1 million.

IPC recognizes interest accrued related to unrecognized tax benefits as interest expense and penalties as other expense. During the years ended December 31, 2008 and 2007, IPC recognized a net reduction in interest expense of $0.1 million and $1 million, respectively. IPC had accrued interest of $0.2 million and $5.5 million as of December 31, 2008 and 2007, respectively. No penalties are accrued.

IPC is subject to examination by their major tax jurisdictions – U.S. federal and state of Idaho. The open tax years for federal and Idaho are 2006-2008 and 2005-2008, respectively. The IRS began its examination of 2006 in December 2008. IDACORP and IPC are unable to predict the outcome of this examination.

3. COMMON STOCK AND STOCK-BASED COMPENSATION:

Dividend Restrictions: IPC's articles of incorporation contain restrictions on the payment of dividends on its common stock if preferred stock dividends are in arrears. IPC has no outstanding preferred stock. Also, certain provisions of credit facilities contain restrictions on the ratio of debt to total capitalization.

IPC must obtain the approval of the Oregon Public Utility Commission (OPUC) before it could directly or indirectly loan funds or issue notes or give credit on its books to IDACORP.

IPC Common Stock

In 2008 and 2007, IDACORP contributed $37 million and $51 million respectively, of additional equity to IPC. No additional shares of IPC common stock were issued.

Stock-Based Compensation

Through its parent company, IDACORP, IPC has three share-based compensation plans. IDACORP's employee plans are the 2000 Long-Term Incentive and Compensation Plan (LTICP) and the 1994 Restricted Stock Plan (RSP). These plans are intended to align employee and shareholder objectives related to IDACORP's long-term growth. IDACORP also has one non-employee plan, the Director Stock Plan (DSP). The purpose of the DSP is to increase directors' stock ownership through stock-based compensation.

The LTICP for officers, key employees and directors permits the grant of nonqualified stock options, incentive stock options, stock appreciation rights, restricted stock, restricted stock units, performance units, performance shares and other awards. The RSP permits only the grant of restricted stock or performance-based restricted stock. At December 31, 2008, the maximum number of shares available under the LTICP and RSP were 1,568,551 and 68,027, respectively.

The following table shows the compensation cost recognized in income and the tax benefits resulting from these plans, as well as the amounts allocated to IPC for those costs associated with IPC's employees (in thousands of dollars):

	IPC	
	2008	2007
Compensation cost	$ 3,683	$ 2,473
Income tax benefit	$ 1,440	$ 967

No equity compensation costs have been capitalized.

Stock awards: Restricted stock awards have vesting periods of up to four years. Restricted stock awards entitle the recipients to dividends and voting rights, and unvested shares are restricted to disposition and subject to forfeiture under certain circumstances. The fair value of restricted stock awards is measured based on the market price of the underlying common stock on the date of grant and charged to compensation expense over the vesting period based on the number of shares expected to vest.

Performance-based restricted stock awards have vesting periods of three years. Performance awards entitle the recipients to voting rights, and unvested shares are restricted to disposition, subject to forfeiture under certain circumstances, and subject to meeting specific performance conditions. Based on the attainment of the performance conditions, the ultimate award can range from zero to 150 percent of the target award. For awards granted prior to 2006, dividends were paid to recipients at the time they were paid on the common stock. Beginning with the 2006 awards, dividends are accumulated and will be paid out only on shares that eventually vest.

The performance goals for the 2008 awards are independent of each other and equally weighted, and are based on two metrics, cumulative earnings per share (CEPS) and total shareholder return (TSR) relative to a peer group. The fair value of the CEPS portion is based on the market value at the date of grant, reduced by the loss in time-value of the estimated future dividend payments, using an expected quarterly dividend of $0.30. The fair value of the TSR portion is estimated using a statistical model that incorporates the probability of meeting performance targets based on historical returns relative to the peer group. Both performance goals are measured over the three-year vesting period and are charged to compensation expense over the vesting period based on the number of shares expected to vest.

A summary of restricted stock and performance share activity is presented below. IPC share amounts represent the portion of IDACORP amounts related to IPC employees:

	IPC	
	Number of Shares	**Weighted-Average Grant Date Fair Value**
Nonvested shares at January 1, 2008	243,496	$ 28.20
Shares granted	124,031	25.35
Shares forfeited	(40,024)	29.11
Shares vested	(24,246)	31.21
Nonvested shares at December 31, 2008	303,257	$ 26.68

The total fair value of shares vested during the years ended December 31, 2008 and 2007 was $0.8 million and $0.9 million, respectively. At December 31, 2008, IPC had $2.7 million of total unrecognized compensation cost related to nonvested share-based compensation that was expected to vest. IPC's share of this amount was $2.5 million. These costs are expected to be recognized over a weighted-average period of 1.70 years. IPC uses IDACORP original issue and/or treasury shares for these awards.

Stock options: Stock option awards are granted with exercise prices equal to the market value of the stock on the date of grant. The options have a term of 10 years from the grant date and vest over a five-year period. The fair value of each option is amortized into compensation expense using graded-vesting. Beginning in 2006, stock options are not a significant component of share-based compensation awards under the LTICP.

The fair values of all stock option awards have been estimated as of the date of the grant by applying a binomial option pricing model. The application of this model involves assumptions that are judgmental and sensitive in the determination of compensation expense. No options were granted in 2008 or 2007.

The following table presents information about options granted and exercised (in thousands of dollars, except for weighted-average amounts):

	IPC	
	2008	**2007**
Weighted-average grant-date fair value	$ -	$ -
Fair value of options vested	353	579
Intrinsic value of options exercised	182	11
Cash received from exercises	707	40
Tax benefits realized from exercises	71	4

As of December 31, 2008, there was less than $0.1 million of total unrecognized compensation cost related to stock options. These costs are expected to be recognized over a weighted average period of 0.6 years. IPC uses IDACORP original issue and/or treasury shares to satisfy exercised options.

IPC's transactions in IDACORP are summarized below:

	Number of Shares	Weighted-Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value (000s)
IPC				
Outstanding at December 31, 2007	611,243	$ 33.75	4.71	$ 2,310
Exercised	(30,700)	23.04		
Forfeited	(3,547)	30.14		
Outstanding at December 31, 2008	576,996	$ 34.34	3.67	$ 611
Vested or expected to vest at December 31, 2008	575,420	$ 34.35	3.66	$ 611
Exercisable at December 31, 2008	526,105	$ 34.75	3.46	$ 611

4. LONG-TERM DEBT

The following table summarizes long-term debt at December 31:

	2008	2007
	(thousands of dollars)	
First mortgage bonds:	$	$
7.20% Series due 2009	80,000	80,000
6.60% Series due 2011	120,000	120,000
4.75% Series due 2012	100,000	100,000
4.25% Series due 2013	70,000	70,000
6.025% Series due 2018	120,000	-
6% Series due 2032	100,000	100,000
5.50% Series due 2033	70,000	70,000
5.50% Series due 2034	50,000	50,000
5.875% Series due 2034	55,000	55,000
5.30% Series due 2035	60,000	60,000
6.30% Series due 2037	140,000	140,000
6.25% Series due 2037	100,000	100,000
Total first mortgage bonds	1,065,000	945,000
Pollution control revenue bonds:		
Variable Rate Series 2003 due 2024(1)	49,800	49,800
Variable Rate Series 2006 due 2026(1)	116,300	116,300
Variable Rate Series 2000 due 2027	4,360	4,360
Total pollution control revenue bonds	170,460	170,460
American Falls bond guarantee	19,885	19,885
Milner Dam note guarantee	9,573	10,636
Unamortized discount - net	(3,163)	(3,409)
Term Loan Credit Facility	166,100	-
Purchase of pollution control revenue bonds	(166,100)	-
Total long-term debt	$ 1,261,755	$ 1,142,572

(1) Humboldt County and Sweetwater County Pollution Control Revenue bonds are secured by first mortgage bonds, bringing the total first mortgage bonds outstanding at December 31, 2008, to $1.231 billion.

At December 31, 2008, the maturities for the aggregate amount of long-term debt outstanding were (in thousands of dollars):

	2009	2010	2011	2012	2013	Thereafter
IPC	$ 81,064	$ 1,064	$ 121,064	$ 101,064	$ 71,064	$ 886,435

At December 31, 2008 and 2007, the overall effective cost of IPC's outstanding debt was 5.59 percent and 5.72 percent, respectively.

Long-Term Financing
On April 3, 2008, IPC entered into a Selling Agency Agreement with each of Banc of America Securities LLC, BNY Capital Markets, Inc., J.P. Morgan Securities Inc., KeyBanc Capital Markets Inc., Lazard Capital Markets LLC, Piper Jaffray & Co., RBC Capital Markets Corporation, SunTrust Robinson Humphrey, Inc., Wachovia Capital Markets, LLC, Wedbush Morgan Securities Inc. and Wells Fargo Securities, LLC in connection with the issuance and sale by IPC from time to time of up to $350 million aggregate principal amount of First Mortgage Bonds, Secured Medium-Term Notes, Series H. On July 10, 2008, IPC issued $120 million of its 6.025% First Mortgage Bonds, Secured Medium-Term Notes, Series H, due July 15, 2018. IPC used the net proceeds to pay down short-term debt. As of December 31, 2008, IPC has $230 million remaining on a shelf registration statement that can be used for the issuance of first mortgage bonds and unsecured debt.

In January 2007, the IPC Board of Directors approved an increase of the maximum amount of first mortgage bonds issuable by IPC to $1.5 billion. The amount issuable is also restricted by property, earnings and other provisions of the mortgage and supplemental indentures to the mortgage. IPC may amend the indenture and increase this amount without consent of the holders of the first mortgage bonds. The indenture requires that IPC's net earnings must be at least twice the annual interest requirements on all outstanding debt of equal or prior rank, including the bonds that IPC may propose to issue. Under certain circumstances, the net earnings test does not apply, including the issuance of refunding bonds to retire outstanding bonds that mature in less than two years or that are of an equal or higher interest rate, or prior lien bonds.

As of December 31, 2008, IPC could issue under the mortgage approximately $528 million of additional first mortgage bonds based on unfunded property additions and $532 million of additional first mortgage bonds based on retired first mortgage bonds. These amounts are further limited by the $1.5 billion restriction discussed above. At December 31, 2008, unfunded property additions were approximately $880 million.

The mortgage requires IPC to spend or appropriate 15 percent of its annual gross operating revenues for maintenance, retirement or amortization of its properties. IPC may, however, anticipate or make up these expenditures or appropriations within the five years that immediately follow or precede a particular year.

The mortgage secures all bonds issued under the indenture equally and ratably, without preference, priority or distinction. IPC may issue additional first mortgage bonds in the future, and those first mortgage bonds will also be secured by the mortgage. The lien of the indenture constitutes a first mortgage on all the properties of IPC, subject only to certain limited exceptions including liens for taxes and assessments that are not delinquent and minor excepted encumbrances. Certain of the properties of IPC are subject to easements, leases, contracts, covenants, workmen's compensation awards and similar encumbrances and minor defects and clouds common to properties. The mortgage does not create a lien on revenues or profits, or notes or accounts receivable, contracts or choses in action, except as permitted by law during a completed default, securities or cash, except when pledged, or merchandise or equipment manufactured or acquired for resale. The mortgage creates a lien on the interest of IPC in property subsequently acquired, other than excepted property, subject to limitations in the case of consolidation, merger or sale of all or substantially all of the assets of IPC.

Pollution Control Revenue Refunding Bonds
On April 3, 2008, IPC made a mandatory purchase of the $49.8 million Humboldt County, Nevada Pollution Control Revenue Refunding Bonds (Idaho Power Company Project) Series 2003 and the $116.3 million Sweetwater County, Wyoming Pollution

Control Revenue Refunding Bonds (Idaho Power Company Project) Series 2006 (together, the Pollution Control Bonds). IPC initiated this transaction in order to adjust the interest rate period of the pollution control bonds from an auction interest rate period to a weekly interest rate period, effective April 3, 2008. The pollution control bonds remain outstanding and have not been retired or cancelled. The maximum interest rate is 14 percent for the Sweetwater bonds and at specified rates capped at 12 percent for the Humboldt bonds.

The regularly scheduled principal and interest payments on the Series 2006 bonds and principal and interest payments on the bonds upon mandatory redemption on determination of taxability are insured by a financial guaranty insurance policy issued by Ambac Assurance Corporation.

Term Loan Credit Agreement
IPC entered into a $170 million Term Loan Credit Agreement, dated as of April 1, 2008, with JPMorgan Chase Bank, N.A., as administrative agent and lender, and Bank of America, N.A., Union Bank of California, N.A. and Wachovia Bank, National Association, as lenders. The Term Loan Credit Agreement provided for the issuance of term loans by the lenders to IPC on April 1, 2008, in an aggregate principal amount of $170 million. The loans were due on March 31, 2009 and could be prepaid but not reborrowed. IPC used $166.1 million of the proceeds from the loans to effect the mandatory purchase on April 3, 2008, of the Pollution Control Bonds (as discussed above under "Pollution Control Revenue Refunding Bonds") and $3.9 million to pay interest, fees and expenses incurred in connection with the Pollution Control Bonds and the Term Loan Credit Agreement.

On February 4, 2009, IPC entered into a new $170 million Term Loan Credit Agreement with JPMorgan Chase Bank, N.A., as administrative agent and lender, Bank of America, N.A., Union Bank, N.A. and Wachovia Bank, National Association, as lenders. IPC used the proceeds to repay the above mentioned Term Loan Credit Agreement. The loans are due on February 3, 2010, but are subject to earlier payment if IPC remarkets the pollution control revenue refunding bonds discussed below. The loans may be prepaid but may not be reborrowed.

The loans bear interest at either a floating rate or a Eurodollar rate. The floating rate is equal to (i) the highest of (a) the prime rate announced by JPMorgan Chase Bank on such day, (b) the sum of (1) the federal funds effective rate in effect on such day plus (2) 0.5 percent per annum and (c) an amount equal to (1) the LIBO Reference Rate on such day plus (2) 1 percent plus (ii) the applicable margin. The Eurodollar rate is (i) the rate published on the Reuters BBA Libor Rates Page 3750 (or on any successor or substitute page) for dollar deposits with a comparable maturity plus (ii) the applicable margin. The LIBO Reference Rate is the rate appearing on the Reuters BBA Libor Rates Page 3750 (or on any successor or substitute page) as the rate for United States dollar deposits for a one month interest period. The applicable margin is currently 2 percent for Eurodollar advances and 1 percent for floating rate advances, but may be increased or decreased based upon the ratings assigned to IPC's senior unsecured debt by Moody's and S&P.

The new Term Loan Credit Agreement is a short-term arrangement; however, $166.1 million was classified as long-term debt as allowed by SFAS No. 6 *Classification of Short-Term Obligations Expected to Be Refinanced.* IPC has the ability to refinance the loans on a long-term basis by utilizing its credit facility, provided that the aggregate of the commitments utilizing the credit facility and commercial paper outstanding does not exceed $300 million. The remaining $3.9 million of the loans is classified as short-term debt.

5. NOTES PAYABLE:

IPC has a $300 million credit facility that expires on April 25, 2012. Commercial paper may be issued up to the amounts supported by the bank credit facilities. Under these facilities the companies pay a facility fee on the commitment, quarterly in arrears, based on its rating for senior unsecured long-term debt securities without third-party credit enhancement as provided by Moody's and S&P. At December 31, 2008 no loans were outstanding on IPC's facility.

At December 31, 2008, IPC had regulatory authority to incur up to $450 million of short-term indebtedness. Balances and interest rates of IPC's short-term borrowings were as follows at December 31 (in thousands of dollars):

	IPC	
	2008	**2007**
	(thousands of dollars)	
Balances:		
At the end of year	$112,850	$136,585

Average during the year	$151,192	$96,890
Weighted-average interest rate:		
At the end of year	4.89%	5.56%
Average during the year	3.97%	5.54%

6. REGULATORY MATTERS:

Regulatory Assets and Liabilities

The following is a breakdown of IPC's regulatory assets and liabilities (in thousands of dollars):

Description	Remaining Amortization Period	Earning a Return	Not Earning a Return	Total as of December 31, 2008	Total as of December 31, 2007
Regulatory Assets:					
Income Taxes		$ -	$ 335,644	$ 335,644	$ 309,902
Benefit Plans(1)		-	177,348	177,348	17,765
Deferred Pension Costs(1)		-	10,583	10,583	2,797
Conservation	2010	3,942	4,864	8,806	8,107
PCA Deferral	2009	140,821	-	140,821	92,323
FCA Deferral		2,721	-	2,721	-
Oregon Deferral(2)		2,878	-	2,878	5,100
Oregon PCAM Deferral(3)		5,400	-	5,400	-
Asset Retirement Obligations(4)		-	10,907	10,907	12,188
Grid West Loans	2013	65	922	987	1,108
Mark-to-Market Liabilities		-	3,074	3,074	171
Other	2010	77	160	237	379
Total(5)		$ 155,904	$ 543,502	$ 699,406	$ 449,840
Regulatory Liabilities:					
Income Taxes		$ -	$ 46,102	$ 46,102	$ 44,580
Conservation		197	2	199	1,893
FCA Accrual (prior year)	2009	-	1,105	1,105	2,145
Removal Costs(4)		-	156,837	156,837	155,314
Mark-to-Market Assets		-	652	652	586
Other		-	514	514	851
Total(6)		$ 197	$ 205,212	$ 205,409	$ 205,369

(1) See Note 8.
(2) Amortization capped at 10 percent of gross Oregon revenue per year.
(3) Amortization capped at 6 percent of gross Oregon revenue per year beginning after the Oregon Deferral amortization is completed.
(4) See Note 12.
(5) Includes $3,074 and $172 for 2008 and 2007, respectively, reported in other current assets on the balance sheets.
(6) Includes $2,413 and $2,166 for 2008 and 2007, respectively, reported in other current liabilities on the balance sheets.

In the event that recovery of costs through rates becomes unlikely or uncertain, SFAS 71 would no longer apply. If IPC were to discontinue application of SFAS 71 for some or all of its operations, then these items may represent stranded investments. If IPC is not allowed recovery of these investments, it would be required to write off the applicable portion of regulatory assets and the financial effects could be significant.

Idaho Rate Cases
2008 General Rate Case: On January 30, 2009, the IPUC issued an order approving an average annual increase in Idaho base rates, effective February 1, 2009, of 3.1 percent (approximately $20.9 million annually), a return on equity of 10.5 percent and an overall rate of return of 8.18 percent. On February 19, 2009, IPC filed a request for reconsideration with the IPUC. In its filing, IPC asked the IPUC to reconsider four areas having a Idaho jurisdictional combined revenue requirement impact of approximately $8 million annually. Included in these areas is an item that relates to a $3.3 million expense credit received in 2006 as a result of successful litigation with the FERC and other federal agencies (FERC Credit). In the order, the IPUC directed IPC to refund the FERC Credit to customers over a five year period, thereby reducing IPC's annual revenue requirement by approximately $0.7 million during such period. IPC believes that this was contrary to Idaho law. If IPC is unsuccessful in its challenge of the IPUC's ruling on FERC fees, it will recognize a loss for some or all of this amount.

2007 General Rate Case: On June 8, 2007, IPC filed an application with the IPUC requesting an average rate increase of 10.35 percent ($63.9 million annually). On February 28, 2008, the IPUC approved a settlement stipulation that included an average increase in base rates of 5.2 percent (approximately $32.1 million annually), effective March 1, 2008. The settlement did not specify an overall rate of return or a return on equity.

Danskin CT1 Power Plant Rate Case: On March 7, 2008, IPC filed an application with the IPUC requesting recovery of construction costs associated with the gas-fired Danskin CT1 plant located near Mountain Home, Idaho. Danskin CT1 began commercial operations on March 11, 2008. IPC requested adding to rate base approximately $65 million attributable to the cost of constructing the generating facility and the related transmission and interconnection facilities, which would have resulted in a base rate increase of 1.39 percent, or approximately $9 million in annual revenues.

On May 30, 2008, the IPUC authorized IPC to add to its rate base $64.2 million for the Danskin CT1 plant and related facilities, effective June 1, 2008, resulting in a base rate increase of 1.37 percent, or $8.9 million in annual revenues. Costs not approved in this order will be included in future filings.

Deferred Net Power Supply Costs
IPC's deferred net power supply costs consisted of the following at December 31 (in thousands of dollars):

	2008	2007
Idaho PCA current year:		
Deferral for the 2008-2009 rate year(1)	$ -	$ 85,732
Deferral for the 2009-2010 rate year	93,657	-
Idaho PCA true-up awaiting recovery:		
Authorized May 2007	-	6,591
Authorized May 2008	47,164	-
Oregon deferral:		
2001 costs	1,663	2,993
2006 costs	1,215	2,107
2008 PCAM	5,400	-
Total deferral	$ 149,099	$ 97,423

(1) The 2008-2009 PCA deferral balance is reduced by $16.5 million of emission allowance sales in 2007.

Idaho: IPC has a PCA mechanism that provides for annual adjustments to the rates charged to its Idaho retail customers. The PCA tracks IPC's actual net power supply costs (fuel and purchased power less off-system sales) and compares these amounts to net power supply costs currently being recovered in retail rates.

The annual adjustments are based on two components:

- A forecast component, based on a forecast of net power supply costs in the coming year as compared to net power supply costs in base rates; and

- A true-up component, based on the difference between the previous year's actual net power supply costs and the previous year's forecast. This component also includes a balancing mechanism so that, over time, the actual collection or refund of authorized true-up dollars matches the amounts authorized. The true-up component is calculated monthly, and interest is applied to the balance.

Prior to February 1, 2009, the PCA mechanism provided that 90 percent of deviations in power supply costs were to be reflected in IPC's rates for both the forecast and the true-up components.

2008-2009 PCA: On May 30, 2008, the IPUC approved IPC's 2008-2009 PCA and an increase to existing revenues of $73.3 million, effective June 1, 2008, which resulted in an average rate increase to IPC's customers of 10.7 percent. The IPUC's order adopted an IPUC Staff proposal to use a "normal" forecast for power supply costs. The revenue increase is net of $16.5 million of gains from the 2007 sale of excess SO_2 emission allowances, including interest, which the IPUC ordered be applied against the PCA.

2007-2008 PCA: On May 31, 2007, the IPUC approved IPC's 2007-2008 PCA filing. The filing increased the PCA component of customers' rates from the then-existing level, which was $46.8 million below base rates, to a level that is $30.7 million above those base rates. This $77.5 million increase was net of $69.1 million of proceeds from sales of excess SO_2 emission allowances. The new rates became effective June 1, 2007.

Emission Allowances: During 2007, IPC sold 35,000 SO_2 emission allowances for a total of $19.6 million. The sales proceeds allocated to the Idaho jurisdiction were approximately $18.5 million. On April 14, 2008, the IPUC ordered that $16.4 million of these proceeds, including interest, be used to help offset the PCA true-up balances from the 2007-2008 PCA. The order also provided that $0.5 million may be used to fund an energy education program.

In 2005 and early 2006, IPC sold 78,000 SO_2 emission allowances for a total of $81.6 million. The sales proceeds allocated to the Idaho jurisdiction were approximately $76.8 million. On May 12, 2006, the IPUC approved a stipulation that allowed IPC to retain ten percent as a shareholder benefit with the remaining 90 percent plus a carrying charge recorded as a customer benefit. This customer benefit was used to partially offset the PCA true-up balance and was reflected in PCA rates in effect from June 1, 2007, to May 31, 2008.

Oregon: On April 30, 2007, IPC filed for an accounting order with the OPUC to defer net power supply costs for the period from May 1, 2007, through April 30, 2008, in anticipation of higher than "normal" (higher than base) power supply expenses. In the filing, IPC included a forecast of Oregon's jurisdictional share of excess power supply costs of $5.7 million. A hearing is set for April 16, 2009.

On April 28, 2006, IPC filed for an accounting order with the OPUC to defer net power supply costs for the period of May 1, 2006, through April 30, 2007. A settlement agreement was reached with the OPUC Staff and the Citizens' Utility Board in the amount of $2 million, which was approved by the OPUC on December 13, 2007.

The timing of future recovery of Oregon power supply cost deferrals is subject to an Oregon statute that specifically limits rate amortizations of deferred costs to six percent of gross Oregon revenue per year. IPC is currently amortizing through rates power supply costs associated with the western energy situation of 2000 and 2001, which is discussed further under "Note 7 - LEGAL AND ENVIRONMENTAL ISSUES - Western Energy Proceeding at the FERC." Full recovery of the 2001 deferral is not expected until 2009. The 2006-2007 and the 2007-2008 deferrals would have to be amortized sequentially following the full recovery of the 2001 deferral.

Oregon Power Cost Recovery Mechanism: On August 17, 2007, IPC filed an application with the OPUC requesting the approval of a power cost recovery mechanism similar to the Idaho PCA. A joint stipulation was filed with the OPUC on March 14, 2008, and the OPUC approved the stipulation on April 28, 2008.

The stipulation and OPUC order established a power cost recovery mechanism with two components: the annual power cost update (APCU) and the power cost adjustment mechanism (PCAM). The combination of the APCU and the PCAM allows IPC to recover excess net power supply costs in a more timely fashion than through the previously existing deferral process.

APCU: The APCU allows IPC to reestablish its Oregon base net power supply costs annually, separate from a general rate case, and to forecast net power supply costs for the upcoming water year. The APCU has two components: the "October Update," where each October IPC calculates its estimated normalized net power supply expenses for the following April through March test period, and the "March Forecast," where each March IPC files a forecast of its expected net power supply expenses for the same test period, updated for a number of variables including the most recent stream flow data and future wholesale electric prices. On June 1 of each year, rates are adjusted to reflect costs calculated in the APCU.

On October 29, 2007, IPC filed the October Update portion of its 2008 APCU with the OPUC reflecting the estimated net power supply expenses for the April 2008 through March 2009 test period. On March 24, 2008, IPC submitted testimony to the OPUC revising its calculation of the October Update to conform to the methodology agreed to by the parties in the stipulation. IPC also submitted the March Forecast, reflecting expected hydroelectric generating conditions and forward prices for the April 2008 through March 2009 test period. The expected power supply costs of $150 million represented an increase of approximately $23 million over the October Update.

On May 20, 2008, the OPUC approved IPC's 2008 APCU (comprising both the October Update and the March Forecast) with the new rates effective June 1, 2008. The approved APCU resulted in a $4.8 million, or 15.69 percent, increase in Oregon revenues.

On October 23, 2008, IPC filed the October Update portion of its 2009 APCU with the OPUC. The filing, combined with supplemental testimony filed on December 1, 2008, reflects that revenues associated with IPC's base net power supply costs would be increased by $1.6 million over the previous October Update, an average 4.55 percent increase. The October Update will be combined with the March Forecast portion of the 2009 APCU, with final rates expected to become effective on June 1, 2009.

PCAM: The PCAM is a true-up to be filed annually in February. The filing calculates the deviation between actual net power supply expenses incurred for the preceding calendar year and the net power supply expenses recovered through the APCU for the same period. Under the PCAM, IPC is subject to a portion of the business risk or benefit associated with this deviation through application of an asymmetrical deadband (or range of deviations) within which IPC absorbs cost increases or decreases. For deviations in actual power supply costs outside of the deadband, the PCAM provides for 90/10 sharing of costs and benefits between customers and IPC. However, a collection will occur only to the extent that it results in IPC's actual return on equity (ROE) for the year being no greater than 100 basis points below IPC's last authorized ROE. A refund will occur only to the extent that it results in IPC's actual ROE for that year being no less than 100 basis points above IPC's last authorized ROE. The PCAM rate is then added to or subtracted from the APCU rate, with new combined rates effective each June 1.

On October 6, 2008, the OPUC provided an order clarifying that the PCAM is a deferral under the Oregon statute. IPC expects that deferrals under the PCAM component will be subject to the six percent limitation on annual amortization discussed above. IPC had $5.4 million deferred under the PCAM as of December 31, 2008.

Fixed Cost Adjustment Mechanism (FCA)

On March 12, 2007, the IPUC approved the implementation of a FCA mechanism pilot program for IPC's residential and small general service customers. The FCA is a rate mechanism designed to remove IPC's disincentive to invest in energy efficiency programs by separating (or decoupling) the recovery of fixed costs from the variable kilowatt-hour charge and linking it instead to a set amount per customer. In the FCA, for each customer class, the number of customers is multiplied by a fixed cost per customer. The cost per customer is based on IPC's revenue requirement as established in a general rate case. This authorized fixed cost recovery amount is compared to the amount of fixed costs actually recovered by IPC. The amount of over- or under-recovery is then returned to or collected from customers in a subsequent rate adjustment. The pilot program began on January 1, 2007, and runs through 2009, with the first rate adjustment occurring on June 1, 2008, and subsequent rate adjustments occurring on June 1 of each year during its term.

On March 14, 2008, IPC filed an application requesting a $2.4 million rate reduction under the FCA pilot program for the net over-recovery of fixed costs during 2007. On May 30, 2008, the IPUC approved the rate reduction of $2.4 million to be distributed to residential and small general service customer classes equally on an energy used basis during the June 1, 2008, through May 31, 2009, FCA year. IPC deferred $2.5 million of FCA net under-recovery of fixed costs during 2008.

Idaho Energy Efficiency Rider (Rider) Prudency Review

IPC's Rider is the chief funding mechanism for IPC's investment in conservation, energy efficiency and demand response programs. Effective June 1, 2008, IPC collects 2.5 percent of base revenues, or approximately $17 million annually, under the Rider. Prior to that date, IPC collected 1.5 percent of base revenues, with funding caps for residential and irrigation customers.

In the 2008 general rate case, IPC requested that the IPUC explicitly find that IPC's expenditures between 2002 and 2007 of $29 million of funds obtained from the Rider were prudently incurred and would, therefore, no longer be subject to potential disallowance. The IPUC Staff recommended that the IPUC defer a prudency determination for these expenditures until IPC was able to provide a comprehensive evaluation package of its programs and efforts. IPC contended that sufficient information had already been provided to the IPUC Staff for review.

On February 18, 2009, IPC filed a stipulation with the IPUC reflecting an agreement with the IPUC Staff on $14.3 million of the Rider funds. The IPUC Staff agreed that this portion of the Rider expenditures were prudently incurred. IPC and the IPUC Staff agreed to continue to exchange information and discuss settlement with regard to the remaining $14.7 million, and IPC will file a pleading with the IPUC by April 1, 2009 seeking a prudency determination on the remainder. If resolution with respect to the remaining $14.7 million cannot be reached in the proceedings stemming from the April 1 filing, IPC and the IPUC Staff will recommend a procedure to allow the IPUC to make such a determination.

Open Access Transmission Tariff (OATT)

On March 24, 2006, IPC submitted a revised OATT filing with the FERC requesting an increase in transmission rates. In the filing, IPC proposed to move from a fixed rate to a formula rate, which allows for transmission rates to be updated each year based on financial and operational data IPC files annually with the FERC in its Form 1. The formula rate request included a rate of return on equity of 11.25 percent. IPC's filing was opposed by several affected parties. Effective June 1, 2006, the FERC accepted IPC's proposed new rates, subject to refund pending the outcome of the hearing and settlement process.

On August 8, 2007, the FERC approved a settlement agreement by the parties on all issues except the treatment of contracts for transmission service that contain their own terms, conditions and rates that were in existence before the implementation of OATT in 1996 (Legacy Agreements). This settlement reduced IPC's proposed new rates and, as a result, approximately $1.7 million collected in excess of the settlement rates between June 1, 2006, and July 31, 2007, was refunded with interest in August 2007. As part of the settlement agreement, the FERC established an authorized rate of return on equity of 10.7 percent.

On August 31, 2007, the FERC Presiding Administrative Law Judge (ALJ) issued an initial decision (Initial Decision) with respect to the treatment of the Legacy Agreements, which would have further reduced the new transmission rates. IPC, as well as the opposing parties, appealed the Initial Decision to the FERC. If implemented, the Initial Decision would have required IPC to make additional refunds, including interest, of approximately $5.4 million (including $0.4 million of interest) for the June 1, 2006, through December 31, 2008, period. IPC previously reserved this entire amount.

On January 15, 2009, the FERC issued an Order on Initial Decision (FERC Order), which upheld the Initial Decision of the ALJ in most respects, but modified the Initial Decision in one respect that is unfavorable to IPC. The decision requires IPC to reduce its transmission service rates to FERC jurisdictional customers. Furthermore, IPC is required to make refunds to FERC jurisdictional transmission customers in the total amount of $13.3 million (including $1.1 million in interest) for the period since the new rates went into effect in June 2006. Based on the FERC Order IPC has reserved an additional $7.9 million (including $0.7 million in interest) in the fourth quarter of 2008, bringing the total reserve amount to $13.3 million. Prior to the FERC Order, the FERC jurisdictional transmission revenues (net of the $5 million reserve) recorded in the last seven months of 2006, all of 2007 and 2008 were $8.1 million, $13.3 million and $15.8 million, respectively. Under the FERC Order, the transmission revenues would have been $6.4 million in the last seven month of 2006, $11 million in 2007 and $12.6 million in 2008. Refunds were made on February 25, 2009.

IPC filed a request for rehearing with the FERC on February 17, 2009. IPC believes that the treatment of the Legacy Agreements conflicts with precedent. The rehearing request asserts that the FERC order is in error by: (1) requiring IPC to include the contract demands associated with the Legacy Agreements in the OATT formula rate divisor rather than crediting the revenue from the Legacy Agreements against IPC's transmission revenue requirement; (2) concluding that IPC must include the contract demands associated with the Legacy Agreements rather than the customers' coincident peak demands; (3) concluding that the transmission rate contained in one or more of the Legacy Agreements was not a discounted rate; (4) failing to consider the non-monetary benefits received by IPC from the Legacy Agreements; (5) concluding that the services provided under the Legacy Agreements are firm services and therefore should be handled for rate purposes in the same manner as firm services under the OATT; and (6) failing to affirm the rate treatment that has been used for the Legacy Agreements for approximately 30 years.

Pension Expense

In the 2003 Idaho general rate case, the IPUC disallowed recovery of pension expense because there were no current cash contributions being made to the pension plan. On March 20, 2007, IPC requested that the IPUC clarify that IPC can consider future cash contributions made to the pension plan a recoverable cost of service. On June 1, 2007, the IPUC issued an order authorizing IPC to account for its defined benefit pension expense on a cash basis, and to defer and account for pension expense under SFAS 87, *Employers' Accounting for Pensions*, as a regulatory asset. The IPUC acknowledged that it is appropriate for IPC to seek recovery in its revenue requirement of reasonable and prudently incurred pension expense based on actual cash contributions. The regulatory asset created by this order is expected to be amortized to expense to match the revenues received when future pension contributions are recovered through rates. The deferral of pension expense did not begin until $4.1 million of past contributions still recorded on the balance sheet at December 31, 2006, were expensed. For 2007, approximately $2.8 million was deferred to a regulatory asset beginning in the third quarter. In 2008, $7.9 million of pension expense was deferred. IPC did not request a carrying charge on the deferral balance.

7. COMMITMENTS AND CONTINGENCIES:

Purchase Obligations:

As of December 31, 2008, IPC had signed agreements to purchase energy from 92 CSPP facilities with contracts ranging from one to 30 years. Seventy-nine of these facilities, with a combined nameplate capacity of 267 megawatts (MW), were on-line at the end of 2008; the other 13 facilities under contract, with a combined nameplate capacity of 190 MW, are projected to come on-line during 2009 and 2010. The majority of the new facilities will be wind resources which will generate on an intermittent basis. During 2008, IPC purchased 756,014 megawatt-hours (MWh) from these projects at a cost of $45.9 million, resulting in a blended price of 6.1 cents per kilowatt hour. IPC purchased 777,147 megawatt-hours at a cost of $45 million in 2007.

At December 31, 2008, IPC had the following long-term commitments relating to purchases of energy, capacity, transmission rights and fuel:

	2009	2010	2011	2012	2013	Thereafter
			(thousands of dollars)			
Cogeneration and small power production	$ 73,684	$ 76,150	$ 95,579	$ 97,234	$ 94,888	$ 1,334,434
Power and transmission rights	84,040	19,013	15,035	2,655	2,655	10,455
Fuel	65,808	27,179	26,891	6,895	9,664	90,320

In addition, IPC has the following long-term commitments for lease guarantees, equipment, maintenance and services, and industry related fees.

	2009	2010	2011	2012	2013	Thereafter
			(thousands of dollars)			
Operating leases	$ 3,081	$ 2,754	$ 2,327	$ 1,799	$ 1,795	$ 22,654
Equipment, maintenance, and service agreements	82,075	23,284	21,820	1,783	1,724	6,896
FERC and other industry related fees	3,922	3,922	3,922	3,922	3,922	19,612

Guarantees

IPC has agreed to guarantee the performance of reclamation activities at Bridger Coal Company of which Idaho Energy Resources Co., a subsidiary of IPC, owns a one-third interest. This guarantee, which is renewed each December, was $60 million at December 31, 2008. Bridger Coal Company has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. Bridger Coal Company and IPC expect that the fund will be sufficient to cover all such costs. Because of the existence of the fund, the estimated fair value of this guarantee is minimal.

Legal Proceedings

Western Energy Proceedings at the FERC: Throughout this report, the term "western energy situation" is used to refer to the California energy crisis that occurred during 2000 and 2001, and the energy shortages, high prices and blackouts in the western United States. High prices for electricity in California and in western wholesale markets during 2000 and 2001 caused numerous purchasers of electricity in those markets to initiate proceedings seeking refunds. Some of these proceedings (the western energy proceedings) remain pending before the FERC or on appeal to the United States Court of Appeals for the Ninth Circuit (Ninth Circuit).

There are pending in the Ninth Circuit approximately 200 petitions for review of numerous FERC orders regarding the western energy situation, including the California refund proceeding, show cause orders with respect to contentions of market manipulation, and the Pacific Northwest proceedings. Decisions in these appeals may have implications with respect to other pending cases, including those to which IDACORP, IPC or IE are parties. IDACORP, IPC and IE intend to vigorously defend their positions in these proceedings, but are unable to predict the outcome of these matters, except as otherwise stated below, or estimate the impact they may have on their consolidated financial positions, results of operations or cash flows.

California Refund: This proceeding originated with an effort by agencies of the State of California and investor owned utilities in California to obtain refunds for a portion of the spot market sales from sellers of electricity into California markets from October 2, 2000, through June 20, 2001. In April 2001, the FERC issued an order stating that it was establishing a price mitigation plan for sales in the California wholesale electricity market. The FERC's order also included the potential for directing electricity sellers into California from October 2, 2000, through June 20, 2001, to refund portions of their spot market sales prices if the FERC determined that those prices were not just and reasonable. In July 2001, the FERC initiated the California refund proceeding including evidentiary hearings to determine the scope and methodology for determining refunds. After evidentiary hearings, the FERC issued an order on refund liability on March 26, 2003, and later denied the numerous requests for rehearing. The FERC also required the California Independent System Operator (Cal ISO) to make a compliance filing calculating refund amounts. That compliance filing has been delayed on a number of occasions and has not yet been filed with the FERC.

IE and other parties petitioned the Ninth Circuit for review of the FERC's orders on California refunds. As additional FERC orders have been issued, further petitions for review have been filed by potential refund payors, including IE, potential refund recipients and governmental agencies. These cases have been consolidated before the Ninth Circuit. Since the initiation of these cases, the Ninth Circuit has convened a series of case management proceedings to organize these complex cases, while identifying and severing discrete cases that can proceed to briefing and decision and staying action on all of the other consolidated cases.

In its October 2005 decision in the first of the severed cases, the Ninth Circuit concluded that the FERC lacked refund authority over wholesale electrical energy sales made by governmental entities and non-public utilities. In its August 2006 decision in the second severed case, the Ninth Circuit ruled that all transactions that occurred within the California Power Exchange (CalPX) and the Cal ISO markets were proper subjects of the refund proceeding, refused to expand the proceedings into the bilateral market, approved the refund effective date as October 2, 2000, and required the FERC to consider claims that some market participants had violated governing tariff obligations at an earlier date than the refund effective date and expanded the scope of the refund proceeding to include transactions within the CalPX and Cal ISO markets outside the limited 24-hour spot market and energy exchange transactions. These latter aspects of the decision exposed sellers to increased claims for potential refunds.

In 2005, the FERC established a framework for sellers wanting to demonstrate that the generally applicable FERC refund methodology interfered with the recovery of costs. IE and IPC made such a cost filing but it was rejected by the FERC in March 2006. IE and IPC requested rehearing of that rejection and that request remains pending before the FERC. IE and IPC are unable to predict how or when the FERC might rule on the request for rehearing, but its effect is confined to the minority of market participants that opted not to join the settlement described below. Accordingly, IE and IPC believe this matter will not have a material adverse effect on their consolidated financial positions, results of operations or cash flows.

On February 17, 2006, IE and IPC jointly filed with the California Parties (Pacific Gas & Electric Company, San Diego Gas & Electric

Company, Southern California Edison Company, the California Public Utilities Commission, the California Electricity Oversight Board, the California Department of Water Resources and the California Attorney General) an Offer of Settlement at the FERC settling matters encompassed by the California refund proceeding, as well as other FERC proceedings and investigations relating to the western energy matters, including IE's and IPC's cost filing and refund obligation. A number of other parties, representing a small minority of potential refund claims, chose to opt out of the settlement. Under the terms of the settlement, IE and IPC assigned $24.25 million of the rights to accounts receivable from the Cal ISO and CalPX to the California Parties to pay into an escrow account for refunds to settling parties. Amounts from that escrow not used for settling parties and $1.5 million of the remaining IE and IPC receivables that are to be retained by the CalPX are available to fund, at least partially, payment of the claims of any non-settling parties if they prevail in the remaining litigation of this matter. Any excess funds remaining at the end of the case are to be returned to IPC and IE. Approximately $10.25 million of the remaining IE and IPC receivables was paid to IE and IPC under the settlement. In addition, the California Parties released IE and IPC from other claims stemming from the western energy market dysfunctions. The FERC approved the Offer of Settlement on May 22, 2006.

On October 24, 2006, the Port of Seattle petitioned the Ninth Circuit for review of the FERC orders approving the settlement. On October 25, 2007, the Ninth Circuit lifted the stay as to the Port of Seattle's appeal along with two other cases and severed the three cases from the remainder of the consolidated cases. On December 2, 2008, the Ninth Circuit filed an order dismissing the Port of Seattle petitions for review. That dismissal order is now final.

Market Manipulation: As part of the California refund proceeding discussed above and the Pacific Northwest refund proceeding discussed below, the FERC issued an order permitting discovery and the submission of evidence regarding market manipulation by sellers during the western energy situation. On June 25, 2003, the FERC ordered more than 50 entities that participated in the western wholesale power markets between January 1, 2000, and June 20, 2001, including IPC, to show cause why certain trading practices did not constitute gaming ("gaming") or other forms of proscribed market behavior in concert with another party ("partnership") in violation of the Cal ISO and CalPX Tariffs. In 2004, the FERC dismissed the "partnership" show cause proceeding against IPC. The order dismissing IPC from the "partnership" proceedings was not the subject of rehearing requests and is now final. Later in 2004, the FERC approved a settlement of the "gaming" proceeding without finding of wrongdoing by IPC. The Port of Seattle was the only party to appeal the FERC orders approving the "gaming" settlement. On December 8, 2008, the Ninth Circuit issued an order dismissing that appeal. The dismissal order is now final.

The orders establishing the scope of the show cause proceedings are presently the subject of review petitions in the Ninth Circuit. In addition to the two show cause orders, on June 25, 2003, the FERC also issued an order instituting an investigation of anomalous bidding behavior and practices in the western wholesale markets for the time period May 1, 2000, through October 1, 2000, to enable it to review evidence of economic withholding of generation. IPC, along with more than 60 other market participants, responded to the FERC data requests. The FERC terminated its investigations as to IPC on May 12, 2004. Although California government agencies and California investor-owned utilities have appealed the FERC's termination of this investigation as to IPC and more than 30 other market participants, the claims regarding the conduct encompassed by these investigations were released by these parties in the California refund settlement discussed above. IE and IPC are unable to predict the outcome of these matters, but believe that the releases govern any potential claims that might arise and that this matter will not have a material adverse effect on their consolidated financial positions, results of operations or cash flows.

Pacific Northwest Refund: On July 25, 2001, the FERC issued an order establishing a proceeding separate from the California refund proceeding to determine whether there may have been unjust and unreasonable charges for spot market sales in the Pacific Northwest during the period December 25, 2000, through June 20, 2001, because the spot market in the Pacific Northwest was affected by the dysfunction in the California market. In late 2001, a FERC Administrative Law Judge concluded that the contracts at issue were governed by the substantially more strict *Mobile-Sierra* standard of review rather than the just and reasonable standard, that the Pacific Northwest spot markets were competitive and that refunds should not be allowed. After the Judge's recommendation was issued, the FERC reopened the proceeding to allow the submission of additional evidence directly to the FERC related to alleged manipulation of the power market by market participants. In 2003, the FERC terminated the proceeding and declined to order refunds. Multiple parties filed petitions for review in the Ninth Circuit and in 2007 the Ninth Circuit issued an opinion, remanding to the FERC the orders that declined to require refunds. The Ninth Circuit's opinion instructed the FERC to consider whether evidence of market manipulation would have altered the agency's conclusions about refunds and directed the FERC to include sales to the California Department of Water Resources proceeding. A number of parties have sought rehearing of the Ninth Circuit's decision. IE and IPC intend to vigorously defend their positions in this proceeding, but are unable to predict the outcome of this matter or estimate the impact it may have on their consolidated financial positions, results of operations or cash flows.

In separate western energy proceedings, the Ninth Circuit issued two decisions on December 19, 2006, regarding the FERC's decision not to require repricing of certain long-term contracts. Those cases originated with individual complaints against specified sellers which did not include IE or IPC. The Ninth Circuit remanded to the FERC for additional consideration the agency's use of restrictive standards of contract review. In its decisions, the Ninth Circuit also questioned the validity of the FERC's administration of its market-based rate regime. On June 26, 2008, the U.S. Supreme Court issued a decision in one of these cases, Morgan Stanley Capital Group Inc. v. Public Utility District No. 1 of Snohomish County (No. 06-1457) (Snohomish), and revisited and clarified the *Mobile-Sierra* doctrine in the context of fixed-rate, forward power contracts. At issue was whether, and under what circumstances, the FERC could modify the rates in such contracts on the grounds that there was a dysfunctional market at the time the contracts were executed. In its decision, the Supreme Court disagreed with many of the conclusions reached by the Ninth Circuit and upheld the application of the *Mobile-Sierra* doctrine even in cases in which it is alleged that the markets were dysfunctional. The Supreme Court nonetheless directed the return of the case to the FERC to (i) consider whether the challenged rates in the case constituted an excessive burden on consumers either at the time the contracts were formed or during the term of the contracts relative to the rates that could have been obtained after elimination of the dysfunctional market and (ii) clarify whether it found the evidence inadequate to support a claim that one of the parties to a contract under consideration engaged in unlawful market manipulation that altered the playing field for the particular contract negotiations-that is, whether there was a causal connection between allegedly unlawful activity and the contract rate. On November 3, 2008, the Ninth Circuit vacated its earlier decision and remanded the case to the FERC for further proceedings consistent with the Supreme Court's decision. On December 18, 2008, the FERC issued its order on remand, establishing settlement proceedings and paper hearing procedures to supplement the record and permit it to respond to the questions specified by the Supreme Court.

This decision is expected to have general implications for contracts in the wholesale electric markets regulated by the FERC, and particular implications for forward power contracts in such markets. The Snohomish decision upholds the application of the *Mobile-Sierra* doctrine to fixed-rate, forward power contracts even in allegedly dysfunctional markets.

IPC and IE have asserted the *Mobile-Sierra* doctrine in the Pacific Northwest proceeding, involving spot market contracts in an allegedly dysfunctional market. IDACORP, IPC and IE are unable to predict how the FERC will rule on Snohomish on remand or how this decision will affect the outcome of the Pacific Northwest proceeding.

Western Shoshone National Council: On April 10, 2006, the Western Shoshone National Council (which purports to be the governing body of the Western Shoshone Nation) and certain of its individual tribal members filed a First Amended Complaint and Demand for Jury Trial in the U.S. District Court for the District of Nevada, naming IPC and other unrelated entities as defendants. Plaintiffs allege that IPC's ownership interest in certain land, minerals, water or other resources was converted and fraudulently conveyed from lands in which the plaintiffs had historical ownership rights and Indian title dating back to the 1860's or before. On May 31, 2007, the U.S. District Court granted the defendants' motion to dismiss stating that the plaintiffs' claims are barred by the finality provision of the Indian Claims Commission Act. Plaintiffs filed a motion for reconsideration which the District Court denied. On January 25, 2008, the District Court entered judgment in favor of IPC. Plaintiffs filed a Notice of Appeal to the Ninth Circuit. The parties have filed briefs on appeal. Oral argument on the appeal has not yet been scheduled. IPC intends to vigorously defend its position in this proceeding, but is unable to predict the outcome of this matter or estimate the impact it may have on IPC's consolidated financial position, results of operations or cash flows.

Sierra Club Lawsuit-Bridger: In February 2007, the Sierra Club and the Wyoming Outdoor Council filed a complaint against PacifiCorp in federal district court in Cheyenne, Wyoming alleging violations of air quality opacity standards at the Jim Bridger coal fired plant in Sweetwater County, Wyoming. Opacity is an indication of the amount of light obscured in the flue gas of a power plant. A formal answer to the complaint was filed by PacifiCorp on April 2, 2007, in which PacifiCorp denied almost all of the allegations and asserted a number of affirmative defenses. IPC is not a party to this proceeding but has a one-third ownership interest in the Plant. PacifiCorp owns a two-thirds interest and is the operator of the Plant. The complaint alleges thousands of opacity permit limit violations by PacifiCorp and seeks a declaration that PacifiCorp has violated opacity limits, a permanent injunction ordering PacifiCorp to comply with such limits, civil penalties of up to $32,500 per day per violation, and reimbursement of the plaintiff's costs of litigation, including reasonable attorney fees.

Discovery in the matter was completed on October 15, 2007. Also in October 2007, the plaintiffs and defendant filed cross-motions for summary judgment on the alleged opacity compliance status of the Plant The court has not yet ruled on these motions. On July 7, 2008, the plaintiffs filed a motion requesting the court to schedule a date for oral argument on the pending motions for summary judgment. On July 17, 2008, PacifiCorp filed an opposition to plaintiffs' motion based on the court's order on Initial Pretrial Conference, which stated that "dispositive motions will be decided on the briefs without oral argument." On November 19, 2008, the plaintiffs filed a motion to refer the pending motions for summary judgment to magistrate judge for recommendation decision. On December 2, 2008, PacifiCorp filed an opposition to plaintiff's motion. The court has yet to rule on either motion filed by plaintiffs. IPC continues to monitor the status of this matter but is unable to predict the outcome of this matter or estimate the impact it may have on its consolidated financial position, results of operations or cash flows.

Sierra Club Lawsuit – Boardman: On September 30, 2008, Sierra Club and four other non-profit corporations filed a complaint against Portland General Electric Company (PGE) in the U.S. District Court for the District of Oregon alleging opacity permit limit violations at the Boardman coal-fired power plant located in Morrow County, Oregon. The complaint also alleges violations of the Clean Air Act, related federal regulations and the Oregon State Implementation Plan relating to PGE's construction and operation of the plant. The complaint seeks a declaration that PGE has violated opacity limits, a permanent injunction ordering PGE to comply with such limits, injunctive relief requiring PGE to remediate alleged environmental damage and ongoing impacts, civil penalties of up to $32,500 per day per violation and the plaintiffs' cost of litigation, including reasonable attorney fees. IPC is not a party to this proceeding but has a 10 percent ownership interest in the Boardman plant. PGE owns 65 percent and is the operator of the plant.

On December 5, 2008, PGE filed a motion to dismiss nine of the twelve claims asserted by plaintiffs in their complaint, alleging among other arguments that certain claims are barred by the statute of limitations or fail to state a claim upon which the court can grant relief. Plaintiffs' response to the motion is due March 6, 2009, and PGE's reply is due April 3, 2009. IPC intends to monitor the status of this matter but is unable to predict its outcome or what effect this matter may have on its consolidated financial position, results of operations or cash flows.

Snake River Basin Adjudication: IPC is engaged in the Snake River Basin Adjudication (SRBA), a general stream adjudication, commenced in 1987, to define the nature and extent of water rights in the Snake River basin in Idaho, including the water rights of IPC. The initiation of the SRBA resulted from the Swan Falls Agreement, an agreement entered into by IPC and the Governor and Attorney General of Idaho in October 1984 to resolve litigation relating to IPC's water rights at its Swan Falls project. IPC has filed claims to its water rights for hydropower and other uses in the SRBA. Other water users in the basin have also filed claims to water rights. Parties to the SRBA may file objections to water right claims that adversely affect or injure their claimed water rights and the Idaho District Court for the Fifth Judicial District, which has jurisdiction over SRBA matters, then adjudicates the claims and objections and enters a decree defining a party's water rights. IPC has filed claims for all of its hydropower water rights in the SRBA, is actively protecting those water rights, and is objecting to claims that may potentially injure or affect those water rights. One such claim involves a notice of claim of ownership filed on December 22, 2006, by the State of Idaho, for a portion of the water rights held by IPC that are subject to the Swan Falls Agreement.

On May 10, 2007, in order to protect its claims and the availability of water for power purposes at its facilities, and in response to the claim of ownership filed by the State of Idaho, IPC filed a complaint and petition for declaratory and injunctive relief regarding the status and nature of IPC's water rights and the respective rights and responsibilities of the parties under the Swan Falls Agreement. The complaint was filed in the Idaho District Court for the Fifth Judicial District, the court with jurisdiction over the SRBA, against the State of Idaho, the Governor, the Attorney General, the Idaho Department of Water Resources (IDWR) and the Director of the IDWR.

In conjunction with the filing of the complaint and petition, IPC filed motions with the court to stay all pending proceedings involving the water rights of IPC and to consolidate those proceedings into a single action where all issues relating to the Swan Falls Agreement can be determined.

IPC alleged in the complaint, among other things, that contrary to the parties' belief at the time the Swan Falls Agreement was entered into in 1984, the Snake River basin above Swan Falls was over-appropriated and as a consequence there was not in 1984, and there currently is not, water available for new upstream uses over and above the minimum flows established by the Swan Falls Agreement; that because of this mutual mistake of fact relating to the over-appropriation of the basin, the Swan Falls Agreement should be reformed; that the state's December 22, 2006, claim of ownership to IPC's water rights should be denied; and that the Swan Falls Agreement did not subordinate IPC's water rights to aquifer recharge.

On April 18, 2008, the court issued a Memorandum Decision and Order on Cross-Motions for Summary Judgment upholding the Swan

Falls Agreement. Under the Swan Falls Agreement, water rights in excess of the minimum flows established by the agreement are held in trust by the State of Idaho for the use and benefit of IPC and the people of the State of Idaho. Water above these minimum flows is available for subsequent consumptive beneficial uses that are approved in accordance with state law. The court further held that to the extent that the state is not meeting the minimum flows or it is anticipated that the minimum flows will not be met, IPC's water rights that are held in trust are not available for subsequent appropriations and that any appropriations already in place may be subject to curtailment in order to meet the minimum flows. The court found that it was not necessary to address the issue of mutual mistake of fact relating to the over-appropriation of the basin because it found that it was water rights that were the subject of the trust arrangement and not the water itself. The court also stated that issues relating to water availability relate to the administration of water rights and should be addressed, as necessary, in an administrative action before the IDWR.

The court did not decide the issue of whether the Swan Falls Agreement subordinated IPC's water rights to groundwater recharge. The State of Idaho and IPC filed summary judgment motions on the recharge issue and completed briefing on the issue. The court held a hearing on December 4, 2008 on the summary judgment motions. After argument, the court took the matter under advisement. IPC is unable to predict how the court will rule on the issue of whether the Swan Falls Agreement subordinated IPC's water rights to groundwater recharge. Based upon recent developments, however, resolution of that issue is not expected to have a significant effect on the availability of water to IPC's hydropower facilities. IPC is cooperating with the State of Idaho and other water users through an advisory committee in the development of the CAMP to protect and enhance water levels in the Eastern Snake Plain Aquifer (ESPA) and the connected Snake River. Many CAMP committee members had early expectations that groundwater recharge would be a significant component of the plan and while many believe that groundwater recharge is a very high-priority issue, further study and review has revealed that significant groundwater recharge is not feasible due to the complex hydrogeology of the ESPA, the lack of infrastructure, and the requirement of compliance with water quality and other environmental standards. IPC is currently engaged in a 3 to 5 year pilot study, in cooperation with IDWR and water users, to determine the temporal and spatial impacts and/or benefits of recharging, a maximum of 30,000 acre-feet of water downstream of American Falls Reservoir on the ESPA Aquifer and the Snake River.

IPC has also filed an action in federal court against the United States Bureau of Reclamation to enforce a contract right for delivery of water to its hydropower projects on the Snake River. In 1923, IPC and the United States entered into a contract that facilitated the development of the American Falls Reservoir by the United States on the Snake River in southeast Idaho. This 1923 contract entitles IPC to 45,000 acrefeet of primary storage capacity in the reservoir and 255,000 acre-feet of secondary storage that was to be available to IPC between October 1 of any year and June 10 of the following year as necessary to maintain specified flows at IPC's Twin Falls power plant below Milner Dam. IPC believes that the United States has failed to deliver this secondary storage, at the specified flows, since 2001. As a result, IPC filed an action in the U.S. District Court of Federal Claims in Washington, D.C. on October 15, 2007 to recover damages from the United States for the lost generation resulting from the reduced flows. On September 30, 2008, IPC filed an amended complaint in which IPC seeks, in addition to damages for breach of the 1923 contract, a prospective declaration of contractual rights so as to prevent the United States from continued failure to fulfill its contractual and fiduciary duties to IPC. On October 2, 2008, the court set a discovery schedule requiring that discovery be completed and pre-trial motions filed by October 1, 2009. The court will then set the matter for trial. IPC is unable to predict the outcome of this action or what effect this matter may have on its consolidated financial position, results of operations or cash flows.

Renfro Dairy: On September 28, 2007, the principals of Renfro Dairy in Canyon County, Idaho filed a lawsuit in the District Court of the Third Judicial District of the State of Idaho against IDACORP and IPC. The plaintiffs' complaint asserts claims for negligence, negligence *per se*, gross negligence, nuisance, and fraud. The claims are based on allegations that from 1972 until at least March 2005, IPC discharged "stray voltage" from its electrical facilities that caused physical harm and injury to the plaintiffs' dairy herd. Plaintiffs seek compensatory damages of not less than $1 million.

On June 9, 2008, IDACORP and IPC filed a motion to dismiss the complaint, contending that the court lacks jurisdiction over the matter because plaintiffs have failed to exhaust administrative remedies before the IPUC. The motion to dismiss was argued and submitted on September 25, 2008. On October 30, 2008, the court issued a decision granting the motion to dismiss. On November 13, 2008, plaintiffs filed a motion to reconsider the court's decision. On December 22, 2008, the court denied the plaintiffs motion to reconsider. On February 20, 2009, plaintiffs filed a notice of appeal of the court's dismissal of the action. The companies intend to vigorously defend their position in this proceeding and believe this matter will not have a material adverse effect on their consolidated financial positions, results of operations or cash flows.

Oregon Trail Heights Fire: On August 25, 2008, a fire ignited beneath an IPC distribution line in Boise, Idaho. It was fanned by high winds and spread rapidly, resulting in one death, the destruction of 10 homes and damage or alleged fire related losses to approximately 30 others. Following the investigation, the Boise Fire Department determined that the fire was linked to a piece of line hardware on one of IPC's distribution poles and that high winds contributed to the fire and its resultant damage.

IPC has received claims from a number of the homeowners and their insurers and is continuing its investigation of these claims. IPC is insured up to policy limits against liability for claims in excess of its self-insured retention. IPC has accrued a reserve for any loss that is probable and reasonably estimable, including insurance deductibles, and believes this matter will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

Other Legal Proceedings: From time to time IPC is party to legal claims, actions and complaints in addition to those discussed above. Although they will vigorously defend against them, they are unable to predict with certainty whether or not they will ultimately be successful. However, based on the companies' evaluation, they believe that the resolution of these matters, taking into account existing reserves, will not have a material adverse effect on IPC's financial position, results of operations or cash flows.

8. BENEFIT PLANS:

SFAS 158

In December 2006, IDACORP and IPC adopted the recognition provisions of Statement of Financial Accounting Standards No. 158, *Employers' Accounting for Defined Benefit Pension Plans and Other Postretirement Plans - an amendment of FASB Statements No. 87, 88, 106, and 132(R).*

The measurement provisions of SFAS 158 were adopted as of January 1, 2008 and require that IPC measure its plan assets and benefit obligations as of its balance sheet date. IPC already used a December 31 measurement date for its plans, so adoption of the measurement provisions of SFAS 158 did not have any effect on IPC's results of operations or cash flows.

Pension Plans

IPC has a noncontributory defined benefit pension plan covering most employees. The benefits under the plan are based on years of service and the employee's final average earnings. IPC's policy is to fund, with an independent corporate trustee, at least the minimum required under the Employee Retirement Income Security Act of 1974 (ERISA) but not more than the maximum amount deductible for income tax purposes. IPC was not required to contribute to the plan in 2008 and 2007. The market-related value of assets for the plan is equal to the fair value of the assets. Fair value is determined by utilizing publicly quoted market values and independent pricing services depending on the nature of the asset, as reported by the trustee/custodian of the plan.

In addition, IPC has a nonqualified, deferred compensation plan for certain senior management employees and directors called the Senior Management Security Plan (SMSP). At December 31, 2008 and 2007, approximately $39.9 million and $48.2 million, respectively, of life insurance policies and investments in marketable securities, all of which are held by a trustee, were designated to satisfy the projected benefit obligation of the plan but do not qualify as plan assets in the actuarial computation of the funded status.

The following table summarizes the changes in benefit obligations and plan assets of these plans:

	Pension Plan		SMSP	
	2008	2007	2008	2007
	(thousands of dollars)			
Change in benefit obligation:				
Benefit obligation at January 1	$ 420,526	$ 425,599	$ 43,153	$ 41,866
Service cost	14,920	15,213	1,278	1,409
Interest cost	26,393	24,457	2,669	2,372
Actuarial loss (gain)	19,547	(29,585)	3,376	(87)
Benefits paid	(16,970)	(15,158)	(2,644)	(2,700)
Plan amendments	-	-	561	293
Benefit obligation at December 31	464,416	420,526	48,393	43,153
Change in plan assets:				

Fair value at January 1		407,970		400,924		-		-
Actual return on plan assets		(95,676)		22,204		-		-
Benefits paid		(16,970)		(15,158)		-		-
Fair value at December 31		295,324		407,970		-		-
Funded status at end of year	$	(169,092)	$	(12,556)	$	(48,393)	$	(43,153)
Amounts recognized in the statement of financial position consist of:								
Other current liabilities	$	-	$	-	$	(2,883)	$	(2,596)
Noncurrent liabilities (1)		(169,092)		(12,556)		(45,510)		(40,557)
Net amount recognized	$	(169,092)	$	(12,556)	$	(48,393)	$	(43,153)
Amounts recognized in accumulated other comprehensive income consist of:								
Net loss	$	155,289	$	5,954	$	12,088	$	9,200
Prior service cost		3,155		3,805		2,209		1,841
Subtotal		158,444		9,759		14,297		11,041
Less amount recorded as regulatory asset		(158,444)		(9,759)		-		-
Net amount recognized in accumulated other comprehensive income	$	-	$	-	$	14,297	$	11,041
Accumulated benefit obligation	$	385,002	$	346,477	$	44,275	$	39,851

(1) Noncurrent liabilities are contained in IPC's Balance Sheets under "Other liabilities" and "Other deferred credits," respectively.

The following table shows the components of net periodic benefit cost for these plans:

	Pension Plan		SMSP	
	2008	2007	2008	2007
	(thousands of dollars)			
Service cost	$ 14,920	$ 15,213	$ 1,278	$ 1,409
Interest cost	26,393	24,457	2,669	2,372
Expected return on assets	(34,112)	(33,387)	-	-
Amortization of net loss	-	-	489	566
Amortization of prior service cost	650	650	192	173
Net periodic pension cost	$ 7,851	$ 6,933	$ 4,628	$ 4,520

In 2009, IPC expects to recognize as components of net periodic benefit cost $10 million from amortizing amounts recorded in accumulated other comprehensive income (or as a regulatory asset for the pension plan) as of December 31, 2008, relating to the pension and SMSP plans. This amount consists of $8.5 million of net loss and $0.6 million of prior service cost for the pension plan and $0.7 million of net loss and $0.2 million of prior service cost for the SMSP.

The following table summarizes the expected future benefit payments of these plans:

	2009	2010	2011	2012	2013	2014-2017
			(thousands of dollars)			
Pension Plan	$ 17,616	$ 18,968	$ 20,525	$ 22,464	$ 24,655	$ 157,832
SMSP	$ 2,963	$ 3,122	$ 3,165	$ 3,276	$ 3,473	$ 19,863

Postretirement Benefits

IPC maintains a defined benefit postretirement plan (consisting of health care and death benefits) that covers all employees who were enrolled in the active group plan at the time of retirement as well as their spouses and qualifying dependents. Benefits for employees who retire after December 31, 2002, are limited to a fixed amount, which will limit the growth of IPC's future obligations under this plan.

The net periodic postretirement benefit cost was as follows (in thousands of dollars):

	2008	2007
Service cost	$ 1,154	$ 1,368
Interest cost	3,498	3,512
Expected return on plan assets	(2,899)	(2,777)
Amortization of unrecognized transition obligation	2,040	2,040
Amortization of prior service cost	(535)	(535)
Amortization of net loss	-	403
Net periodic postretirement benefit cost	$ 3,258	$ 4,011

The following table summarizes the changes in benefit obligation and plan assets (in thousands of dollars):

	2008	2007
Change in accumulated benefit obligation:		
Benefit obligation at January 1	$ 56,826	$ 62,913
Service cost	1,154	1,368
Interest cost	3,498	3,512
Actuarial (gain) loss	1,656	(7,431)
Benefits paid(1)	(3,486)	(3,536)
Benefit obligation at December 31	59,648	56,826
Change in plan assets:		
Fair value of plan assets at January 1	35,096	32,627
Actual return on plan assets	(7,834)	3,129
Employer contributions	1,507	2,876
Benefits paid(1)	(3,486)	(3,536)
Fair value of plan assets at December 31	25,283	35,096
Funded status at end of year (included in noncurrent liabilities)(2)	$ (34,365)	$ (21,730)

(1) Benefits paid are net of $1,927 and $1,646 of plan participant contributions, and $421 and $405 of Medicare Part D subsidy receipts for 2008 and 2007, respectively.

(2) Noncurrent liabilities are contained in "Other deferred credits" for IPC.

Amounts recognized in accumulated other comprehensive income consist of:

	2008	2007
Net loss	$ 16,289	$ 3,900
Prior service cost (credit)	(2,072)	(2,607)
Transition obligation	8,160	10,200
Subtotal	22,377	11,493
Less amount recognized in regulatory assets	(18,904)	(8,006)
Less amount included in deferred tax assets	(3,473)	(3,487)
Net amount recognized in accumulated other comprehensive income	$ -	$ -

In 2009, IPC expects to recognize as components of net periodic benefit cost $2.3 million from amortizing amounts recorded in accumulated other comprehensive income as of December 31, 2008 relating to the postretirement plan. This amount consists of ($0.5) million of prior service cost, $0.8 million of net loss and $2.0 million of transition obligation.

Medicare Act: The Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Medicare Act) was signed into law in December 2003 and established a prescription drug benefit, as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a prescription drug benefit that is at least actuarially equivalent to Medicare's prescription drug coverage.

The following table summarizes the expected future benefit payments of the postretirement benefit plan and expected Medicare Part D subsidy receipts (in thousands of dollars):

	2009	2010	2011	2012	2013	2014-2018
Expected benefit payments(1)	$ 4,100	$ 4,300	$ 4,400	$ 4,500	$ 4,700	$ 24,800
Expected Medicare Part D subsidy receipts	$ 500	$ 600	$ 600	$ 700	$ 800	$ 4,000

(1)Expected benefit payments are net of expected Medicare Part D subsidy receipts.

The assumed health care cost trend rate used to measure the expected cost of health benefits covered by the plan was 10 percent and 6.75 percent in 2008 and 2007, respectively. The assumed health care cost trend rate for 2008 is assumed to decrease gradually to 5 percent over ten years, and remain at that level. The assumed dental cost trend rate used to measure the expected cost of dental benefits covered by the plan was 5 percent and 6.75 percent in 2008 and 2007, respectively. A 1-percentage point change in the assumed health care cost trend rate would have the following effect (in thousands of dollars):

	1-Percentage-Point Increase	1-Percentage-Point Decrease
Effect on total of cost components	$ 245	$ (187)
Effect on accumulated postretirement benefit obligation	$ 2,136	$ (1,700)

The following table sets forth the weighted-average assumptions used at the end of each year to determine benefit obligations for all IPC-sponsored pension and postretirement benefits plans:

	Pension Benefits		Postretirement Benefits	
	2008	2007	2008	2007
Discount rate	6.1%	6.4%	6.1%	6.4%
Rate of compensation increase	4.5%	4.5%	-	-
Medical trend rate	-	-	10.0%	6.75%
Dental trend rate	-	-	5.0%	6.75%
Measurement date	12/31/08	12/31/07	12/31/08	12/31/07

The following table sets forth the weighted-average assumptions used to determine net periodic benefit cost for all IPC-sponsored pension and postretirement benefit plans:

	Pension Benefits		Postretirement Benefits	
	2008	2007	2008	2007
Discount rate	6.4%	5.85%	6.4%	5.85%
Expected long-term rate of return on assets	8.5%	8.5%	8.5%	8.5%
Rate of compensation increase	4.5%	4.5%	-	-
Medical trend rate	-	-	10.0%	6.75%
Dental trend rate	-	-	5.0%	6.75%

Plan Asset Allocations: IPC's pension plan and postretirement benefit plan weighted average asset allocations at December 31, 2008 and 2007, by asset category are as follows:

	Pension Plan	Postretirement Benefits

Asset Category				
Equity securities	58%	65%	-%	-%
Debt securities	28	22	-	-
Real estate	12	10	-	-
Other(1)	2	3	100	100
Total	100%	100%	100%	100%

(1) The postretirement benefit plan assets are primarily life insurance contracts.

Pension Asset Allocation Policy: The target allocations for the portfolio by asset class are as follows:

Large-Cap Growth Stocks	10%	International Growth Stocks	7%
Large-Cap Core Stocks	11%	International Value Stocks	7%
Large-Cap Value Stocks	10%	Intermediate-Term Bonds	13%
Small-Cap Growth Stocks	5%	Short-Term Bonds	10%
Small-Cap Value Stocks	5%	Core Real Estate	9%
Micro-Cap Stocks	3%	Absolute Return	4%
Cash and Cash Equivalents	3%	Private Equity	3%

Assets are rebalanced as necessary to keep the portfolio close to target allocations.

The plan's principal investment objective is to maximize total return (defined as the sum of realized interest and dividend income and realized and unrealized gain or loss in market price) consistent with prudent parameters of risk and the liability profile of the portfolio. Emphasis is placed on preservation and growth of capital along with adequacy of cash flow sufficient to fund current and future payments to pensioners.

There are three major goals in IPC's asset allocation process:

- Determine if the investments have the potential to earn the rate of return assumed in the actuarial liability calculations.
- Match the cash flow needs of the plan. IPC sets cash allocations sufficient to cover the current year benefit payments and bond allocations sufficient to cover at least five years of benefit payments. IPC then utilizes growth instruments (equities, real estate, venture capital) to fund the longer-term liabilities of the plan.
- Maintain a prudent risk profile consistent with ERISA fiduciary standards.

Allowable plan investments include stocks and stock funds, investment-grade bonds and bond funds, core real estate funds, private equity funds, and cash and cash equivalents. With the exception of real estate holdings and private equity, investments must be readily marketable so that an entire holding can be disposed of quickly with only a minor effect upon market price.

Rate-of-return projections for plan assets are based on historical risk/return relationships among asset classes. The primary measure is the historical risk premium each asset class has delivered versus the return on 10-year U.S. Treasury Notes. This historical risk premium is then added to the current yield on 10-year U.S. Treasury Notes, and the result provides a reasonable prediction of future investment performance. Additional analysis is performed to measure the expected range of returns, as well as worst–case and best-case scenarios. Based on the current low interest rate environment, current rate-of-return expectations are lower than the nominal returns generated over the past 20 years when interest rates were generally much higher.

IPC's asset modeling process also utilizes historical market returns to measure the portfolio's exposure to a "worst-case" market scenario, to determine how much performance could vary from the expected "average" performance over various time periods. This "worst-case" modeling, in addition to cash flow matching and diversification by asset class and investment style, provides the basis for managing the risk associated with investing portfolio assets.

Employee Savings Plan

IPC has an Employee Savings Plan that complies with Section 401(k) of the Internal Revenue Code and covers substantially all employees. IPC matches specified percentages of employee contributions to the plan. Matching contributions amounted to $5 million and $5 million in 2008 and 2007, respectively.

Postemployment Benefits
IPC provides certain benefits to former or inactive employees, their beneficiaries and covered dependents after employment but before retirement. These benefits include salary continuation, health care and life insurance for those employees found to be disabled under IPC's disability plans and health care for surviving spouses and dependents. IPC accrues a liability for such benefits. The post employment benefit amounts included in other deferred credits on IPC's consolidated balance sheets at December 31, 2008 and 2007 are $3.7 million and $3.5 million, respectively.

Pension Protection Act
In 2006, the Pension Protection Act of 2006 (the Act), which affects the manner in which many companies, including IDACORP and IPC, administer their pension plans was signed into law. The Act made changes to a variety of rules that apply to employee benefit plans, including those dealing with minimum funding requirements of defined benefit pension plans and plan investments of defined contribution pension plans. The Act also permanently extended the pension law changes made by the Economic Growth and Tax Relief Reconciliation Act of 2001, which had been scheduled to sunset on December 31, 2010. This legislation became effective on January 1, 2008.

In accordance with the Act, companies are required to be 94 percent funded for their outstanding qualified pension obligations as of January 1, 2009, in order to avoid a scheduled series of required annual contributions. As of December 31, 2007, qualified pension liabilities were nearly fully funded; however, recent stock market performance has reduced the value of pension assets during 2008. Therefore, under current provisions of the Act, IPC will need to make additional contributions to become fully funded over a period of seven years. Based on the value of pension assets and interest rates as of December 31, 2008, the estimated contributions would be approximately $45 million in 2010 and $33 million for each of 2011, 2012, and 2013. These estimates reflect the initial relief measures as passed by Congress; however, additional measures are being proposed, which may impact immediate funding requirements.

9. PROPERTY PLANT AND EQUIPMENT AND JOINTLY-OWNED PROJECTS:

The following table presents the major classifications of IPC's utility plant in service, annual depreciation provisions as a percent of average depreciable balance and accumulated provision for depreciation for the years 2008 and 2007 (in thousands of dollars):

	2008		2007	
	Balance	**Avg Rate**	**Balance**	**Avg Rate**
Production	$ 1,736,670	2.34%	$ 1,639,710	2.52%
Transmission	742,871	2.11	684,399	2.13
Distribution	1,254,048	2.50	1,175,429	2.58
General and Other	296,545	7.53	296,801	8.29
Total in service	4,030,134	2.73%	3,796,339	2.95%
Accumulated provision for depreciation	(1,505,120)		(1,468,832)	
In service - net	$ 2,525,014		$ 2,327,507	

IPC has interests in three jointly-owned generating facilities. Under the joint operating agreements, each participating utility is responsible for financing its share of construction, operating and leasing costs. IPC's proportionate share of direct operation and maintenance expenses applicable to the projects is included in the Consolidated Statements of Income.

These facilities, and the extent of IPC's participation, were as follows at December 31, 2008 (in thousands of dollars):

Name of Plant	Location	Utility Plant In Service	Construction Work in Progress	Accumulated Provision for Depreciation	Owner ship %	MW(1)
Jim Bridger Units 1-4	Rock Springs, WY	$ 495,321	$ 16,403	$ 279,296	33	771
Boardman	Boardman, OR	70,924	477	50,914	10	64
Valmy Units 1 and 2	Winnemucca, NV	336,783	8,041	212,791	50	284

(1)IPC share of nameplate capacity

IPC's wholly-owned subsidiary IERCo, is a joint venturer in Bridger Coal Company, which operates the mine supplying coal to the Jim Bridger generating plant. IPC's coal purchases from the joint venture were $63 million, and $51 million in 2008 and 2007, respectively.

IPC has contracts to purchase the energy from four PURPA qualified facilities that are 50 percent owned by Ida-West, a wholly-owned subisidary of IDACORP. IPC's power purchases from these facilities were $8 million in 2008 and 2007.

10. INVESTMENTS:

The following table summarizes IPC's investments as of December 31 (in thousands of dollars):

		2008		2007
IPC Investments:				
Equity method investment	$	86,433	$	76,451
Available-for-sale equity securities		14,451		21,445
Executive deferred compensation		4,679		6,627
Other investments		948		5
Total IPC investments		106,511		104,528

Equity Method Investments

IPC, through its subsidiary IERCo, is a 33 percent owner of Bridger Coal Company, which supplies coal to the Jim Bridger generating plant owned in part by IPC.

The following table presents IPC's earnings (loss) of unconsolidated equity-method investments (in thousands of dollars):

		2008		2007
Bridger Coal Company (IPC)	$	6,772	$	5,553

The following table presents summarized income statement information for Bridger Coal Company (in thousands of dollars):

		2008		2007
Operating revenues	$	187,560	$	153,126
Operating expenses		167,245		136,468
Net Income	$	20,315	$	16,658

The following table presents summarized balance sheet information for Bridger Coal Company (in thousands of dollars):

		2008		2007
Assets				
Current assets	$	64,569	$	58,672
Noncurrent assets		318,266		330,583
Total Assets	$	382,835	$	389,255
Liabilities				
Current liabilities	$	25,182	$	25,372
Noncurrent liabilities		98,355		134,529
Total Liabilities		123,537		159,901
Joint venture capital		259,298		229,353

Total Liabilities and Joint Venture Capital	$	382,835	$	389,254

Investments in Debt and Equity Securities
Investments in debt and equity securities are accounted for in accordance with SFAS 115, *Accounting for Certain Investments in Debt and Equity Securities.* Those investments classified as available-for-sale securities are reported at fair value, using either specific identification or average cost to determine the cost for computing gains or losses. Any unrealized gains or losses on available-for-sale securities are included in other comprehensive income.

Investments classified as held-to-maturity securities are reported at amortized cost. Held-to-maturity securities are investments in debt securities for which the company has the positive intent and ability to hold the securities until maturity. These debt securities have maturities ranging from 2009 through 2025.

The following table summarizes investments in debt and equity securities (in thousands of dollars):

	2008			2007		
	Gross Unrealized Gain	**Gross Unrealized Loss**	**Fair Value**	**Gross Unrealized Gain**	**Gross Unrealized Loss**	**Fair Value**
Available-for-sale securities (IPC)	$ -	$ -	$ 14,451	$ 1,059	$ 128	$ 21,445

The following table summarizes sales of available-for-sale securities (in thousands of dollars):

	2008	**2007**
Proceeds from sales	$ -	$ 26,110
Gross realized gains from sales	-	2,093
Gross realized losses from sales	-	762

Additionally, these investments are evaluated to determine whether they have experienced a decline in market value that is considered other-than-temporary. IPC analyzes securities in loss positions as of the end of each reporting period. Due to recent market conditions IPC reviewed securities in a loss position and determined that due to the severity of the losses and the volatility of the market an other-than-temporary impairment should be recorded. At December 31, 2008, four available-for-sale and six held-to-maturity securities were in an unrealized loss position. The available-for-sale equity securities in unrealized loss positions are in broadly diversified index funds used to fund IPC's SMSP. The held-to-maturity debt securities in unrealized loss positions are bonds, whose market values fluctuate based on the interest rate environment. The available-for-sale securities were in unrealized loss positions of at least 32 percent and were deemed other-than-temporarily impaired and written down $6.8 million to fair market value at December 31, 2008. IPC did not recognize any other-than-temporary impairments in 2007.

The following table summarizes information regarding securities that were in an unrealized loss position at the end of each year, but for which no other-than-temporary impairment was recognized (in thousands of dollars).

	Less than 12 months		12 months or longer	
	Aggregate Unrealized Loss	**Aggregate Related Fair Value**	**Aggregate Unrealized Loss**	**Aggregate Related Fair Value**
2007:				
Available-for-sale equity securities (IPC)	$ 128	$ 1,059	$ -	$ -

11. FAIR VALUE MEASUREMENTS:

IPC partially adopted the provisions of SFAS 157, *Fair Value Measurements* (SFAS 157) on January 1, 2008. SFAS 157 defines fair value, establishes a framework for measuring fair value, establishes a fair value hierarchy based on the quality of inputs used to measure fair value and enhances disclosure requirements for fair value measurements.

FASB Staff Position 157-2, *Effective Date of FASB Statement No. 157* (FSP 157-2) delayed the implementation of SFAS 157 for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). The delay is intended to allow the Board of Directors and constituents additional time to consider the effect of various implementation issues that have arisen, or that may arise, from the application of SFAS 157. In accordance with FSP 157-2, IPC did not apply the provisions of SFAS 157 to asset retirement obligations.

The following tables present information about IDACORP's and IPC's assets and liabilities measured at fair value on a recurring basis as of December 31, 2008 (in thousands of dollars). IDACORP's and IPC's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy.

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Assets:				
Derivatives	$ 652	$ -	$ -	$ 652
Money market funds	1,224	-	-	1,224
Trading securities	4,679	-	-	4,679
Available-for-sale securities	14,451	-	-	14,451
Liabilities:				
Derivatives	$ -	$ (2,653)	$ -	$ (2,653)

In accordance with SFAS 157, IPC have categorized their financial instruments, based on the priority of the inputs to the valuation technique, into a three-level fair value hierarchy. The fair value hierarchy gives the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). If the inputs used to measure the financial instruments fall within different levels of the hierarchy, the categorization is based on the lowest level input that is significant to the fair value measurement of the instrument.

Financial assets and liabilities recorded on the Consolidated Balance Sheets are categorized based on the inputs to the valuation techniques as follows:

Level 1: Financial assets and liabilities whose values are based on unadjusted quoted prices for identical assets or liabilities in an active market that IPC has the ability to access.

Level 2: Financial assets and liabilities whose values are based on the following:

a) Quoted prices for similar assets or liabilities in active markets;
b) Quoted prices for identical or similar assets or liabilities in non-active markets;
c) Pricing models whose inputs are observable for substantially the full term of the asset or liability;
d) Pricing models whose inputs are derived principally from or corroborated by observable market data through correlation or other means for substantially the full term of the asset or liability.

IPC Level 2 inputs are based on quoted market prices adjusted for location using corroborated, observable market data.

Level 3: Financial assets and liabilities whose values are based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement. These inputs reflect management's own assumptions about the assumptions a market participant would use in pricing the asset or liability.

IPC's derivatives are contracts entered into as part of our management of loads and resources. Electricity swaps are valued on the Intercontinental Exchange with quoted prices in an active market. Natural gas derivative valuations are performed using New York Mercantile Exchange (NYMEX) pricing, adjusted for basis location, which are also quoted under NYMEX. Trading securities consists of employee-directed investments held in a Rabbi Trust and are related to an executive deferred compensation plan. Available-for-sale securities are related to the SMSP and are held in a Rabbi Trust and are actively traded money market and equity funds with quoted prices in active markets.

The following tables present the carrying value and estimated fair value of other financial instruments that are not reported at fair value, using available market information and appropriate valuation methodologies. The use of different market assumptions and/or estimation methodologies may have a material effect on the estimated fair value amounts. Cash and cash equivalents, deposits, customer and other receivables, notes payable, accounts payable, interest accrued and taxes accrued are reported at their carrying value as these are a reasonable estimate of their fair value. The estimated fair values for notes receivable and long-term debt are based upon quoted market prices of the same or similar issues or discounted cash flow analyses as appropriate.

	December 31, 2008		December 31, 2007	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	(thousands of dollars)			
Assets:				
Notes receivable	$ 259	$ 282	$ 4,859	$ 4,907
Liabilities:				
Long-term debt	$ 1,268,818	$ 1,191,476	$ 1,145,981	$ 1,272,627

IPC adopted the provisions of SFAS 159, *The Fair Value Option for Financial Assets and Financial Liabilities - Including an Amendment of FASB Statement 115* (SFAS 159) on January 1, 2008. SFAS 159 permits an entity to choose to measure many financial instruments and certain other items at fair value. Most of the provisions in SFAS 159 are elective; however, the amendment to SFAS 115, *Accounting for Certain Investments in Debt and Equity Securities,* applies to all entities with available-for-sale and trading securities. The fair value option established by SFAS 159 permits all entities to choose to measure eligible items at fair value at specified election dates. A business entity reports unrealized gains and losses on items for which the fair value option has been elected in earnings at each subsequent reporting date. The fair value option: (a) may be applied instrument by instrument, with a few exceptions, such as investments otherwise accounted for by the equity method; (b) is irrevocable (unless a new election date occurs); and (c) is applied only to entire instruments and not to portions of instruments. IPC did not elect the fair value option for any existing eligible items, but may consider the fair value option on a case-by-case basis in the future.

12. ASSET RETIREMENT OBLIGATIONS (ARO):

SFAS 143, *Accounting for Asset Retirement Obligations,* as amended and interpreted, requires that legal obligations associated with the retirement of property, plant and equipment be recognized as a liability at fair value when incurred and when a reasonable estimate of the fair value of the liability can be made. Under SFAS 143, when a liability is initially recorded, the entity increases the carrying amount of the related long-lived asset to reflect the future retirement cost. Over time, the liability is accreted to its present value and paid, and the capitalized cost is depreciated over the useful life of the related asset. If, at the end of the asset's life, the recorded liability differs from the actual obligations paid, a gain or loss would be recognized. As a rate-regulated entity, IPC records regulatory assets or liabilities instead of accretion, depreciation and gains or losses, as approved by Order No. 29414 from the IPUC. The regulatory assets recorded under this order do not earn a return on investment.

IPC's recorded AROs relate to the removal of Polychlorinated biphenyls-contaminated equipment at its distribution facilities and the reclamation and removal costs at its jointly owned coal-fired generation facilities. In 2008, changes in estimates for both of these facilities resulted in a net decrease of $2.6 million in the recorded ARO.

IPC also has AROs associated with its transmission system and hydroelectric facilities; however, due to the indeterminate removal date, the fair value of the associated liabilities currently cannot be estimated and no amounts are recognized in the consolidated financial statements.

The regulated operations of IPC also collect removal costs in rates for certain assets that do not have associated AROs. The adoption of SFAS 143 required IPC to redesignate these removal costs as regulatory liabilities. Costs recorded as regulatory liabilities on IDACORP's and IPC's Consolidated Balance Sheets as of December 31, 2008 and 2007, were $157 million and $155 million, respectively.

The following table presents the changes in the carrying amount of AROs (in thousands of dollars):

	2008	2007
Balance at beginning of year	$ 14,515	$ 12,911
Accretion expense	701	692
Revisions in estimated cash flows	(2,627)	920
Liability settled	(174)	(8)
Balance at end of year	$ 12,415	$ 14,515

13. RELATED PARTY TRANSACTIONS (IPC):

IDACORP

IPC performs corporate functions such as financial, legal and management services for IDACORP and its subsidiaries. IPC charges IDACORP for the costs of these services based on service agreements and other specifically identified costs. For these services IPC billed IDACORP $1 million and $2 million in 2008 and 2007, respectively.

Ida-West

IPC purchases all of the power generated by four of Ida-West's hydroelectric projects located in Idaho. IPC paid $8 million in 2008 and 2007.

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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	1,310,950			(7,048,073)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	(922,013)			450,330
3	Preceding Quarter/Year to Date Changes in Fair Value	178,312			(126,005)
4	Total (lines 2 and 3)	(743,701)			324,325
5	Balance of Account 219 at End of Preceding Quarter/Year	567,249			(6,723,748)
6	Balance of Account 219 at Beginning of Current Year	567,249			(6,723,748)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	4,159,139			414,660
8	Current Quarter/Year to Date Changes in Fair Value	(4,726,364)			(2,397,551)
9	Total (lines 7 and 8)	(567,225)			(1,982,891)
10	Balance of Account 219 at End of Current Quarter/Year	24			(8,706,639)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/Q4

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1			(5,737,123)		
2			(471,683)		
3			52,307		
4			(419,376)	76,579,025	76,159,649
5			(6,156,499)		
6			(6,156,499)		
7			4,573,799		
8			(7,123,915)		
9			(2,550,116)	94,114,928	91,564,812
10			(8,706,615)		

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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)	4,030,588,348	4,030,588,348
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	4,030,588,348	4,030,588,348
9	Leased to Others		
10	Held for Future Use	6,318,163	6,318,163
11	Construction Work in Progress	207,662,162	207,662,162
12	Acquisition Adjustments	-454,449	-454,449
13	Total Utility Plant (8 thru 12)	4,244,114,224	4,244,114,224
14	Accum Prov for Depr, Amort, & Depl	1,505,119,564	1,505,119,564
15	Net Utility Plant (13 less 14)	2,738,994,660	2,738,994,660
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	1,486,751,090	1,486,751,090
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	18,741,500	18,741,500
22	Total In Service (18 thru 21)	1,505,492,590	1,505,492,590
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	-373,026	-373,026
33	Total Accum Prov (equals 14) (22,26,30,31,32)	1,505,119,564	1,505,119,564

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/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	5,703	50,244
3	(302) Franchises and Consents	21,771,624	2,560
4	(303) Miscellaneous Intangible Plant	49,014,582	9,444,368
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	70,791,909	9,497,172
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,370,320	
9	(311) Structures and Improvements	131,443,882	3,332,215
10	(312) Boiler Plant Equipment	524,719,259	19,563,633
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	126,933,587	7,071,713
13	(315) Accessory Electric Equipment	61,605,735	1,416,574
14	(316) Misc. Power Plant Equipment	14,627,692	2,414,071
15	(317) Asset Retirement Costs for Steam Production	4,731,236	-369,234
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	865,431,711	33,428,972
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	27,131,877	1,523,291
28	(331) Structures and Improvements	145,349,446	6,000,910
29	(332) Reservoirs, Dams, and Waterways	246,057,906	3,474,423
30	(333) Water Wheels, Turbines, and Generators	187,855,934	484,283
31	(334) Accessory Electric Equipment	37,573,489	3,971,251
32	(335) Misc. Power PLant Equipment	16,288,729	1,189,254
33	(336) Roads, Railroads, and Bridges	7,492,685	
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	667,750,066	16,643,412
36	D. Other Production Plant		
37	(340) Land and Land Rights	402,746	
38	(341) Structures and Improvements	5,765,947	4,656,059
39	(342) Fuel Holders, Products, and Accessories	3,765,689	1,564,891
40	(343) Prime Movers	43,597,392	48,133,339
41	(344) Generators	36,682,334	-444,466
42	(345) Accessory Electric Equipment	14,055,647	3,867,501
43	(346) Misc. Power Plant Equipment	2,258,227	1,539,837
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	106,527,982	59,317,161
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,639,709,759	109,389,545

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

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

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

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

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			55,947		2
60,000			21,714,184		3
25,394,367			33,064,583		4
25,454,367			54,834,714		5
					6
					7
			1,370,320		8
266,953			134,509,144		9
7,669,836			536,613,056		10
					11
1,444,724			132,560,576		12
860,134			62,162,175		13
698,604			16,343,159		14
			4,362,002		15
10,940,251			887,920,432		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			28,655,168		27
73,299			151,277,057		28
24,346			249,507,983		29
65,598			188,274,619		30
214,024			41,330,716		31
10,020			17,467,963		32
			7,492,685		33
					34
387,287			684,006,191		35
					36
			402,746		37
			10,422,006		38
			5,330,580		39
241,306			91,489,425		40
			36,237,868		41
685,167			17,237,981		42
174,918			3,623,146		43
					44
1,101,391			164,743,752		45
12,428,929			1,736,670,375		46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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	31,094,271	3,573,713
49	(352) Structures and Improvements	40,254,296	1,041,187
50	(353) Station Equipment	262,977,911	25,222,555
51	(354) Towers and Fixtures	121,741,698	15,244,442
52	(355) Poles and Fixtures	88,360,864	5,331,099
53	(356) Overhead Conductors and Devices	139,652,134	11,603,174
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices		
56	(359) Roads and Trails	318,351	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	684,399,525	62,016,170
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	4,385,782	334,889
61	(361) Structures and Improvements	21,657,452	2,885,280
62	(362) Station Equipment	151,682,747	15,847,465
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	203,942,364	8,693,766
65	(365) Overhead Conductors and Devices	106,511,815	11,800,654
66	(366) Underground Conduit	46,129,157	1,353,959
67	(367) Underground Conductors and Devices	171,154,321	8,912,213
68	(368) Line Transformers	352,640,906	35,194,821
69	(369) Services	53,887,678	2,099,689
70	(370) Meters	56,322,932	3,631,951
71	(371) Installations on Customer Premises	2,732,980	155,034
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	4,121,273	89,095
74	(374) Asset Retirement Costs for Distribution Plant	259,264	-26,894
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,175,428,671	90,971,922
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	8,873,130	1,955,245
87	(390) Structures and Improvements	68,791,677	3,097,321
88	(391) Office Furniture and Equipment	38,195,783	11,585,956
89	(392) Transportation Equipment	57,256,775	5,634,408
90	(393) Stores Equipment	1,074,679	136,651
91	(394) Tools, Shop and Garage Equipment	4,410,227	571,472
92	(395) Laboratory Equipment	10,232,418	910,339
93	(396) Power Operated Equipment	8,709,964	309,378
94	(397) Communication Equipment	25,893,136	1,460,308
95	(398) Miscellaneous Equipment	3,026,058	1,234,348
96	SUBTOTAL (Enter Total of lines 86 thru 95)	226,463,847	26,895,426
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)	226,463,847	26,895,426
100	TOTAL (Accounts 101 and 106)	3,796,793,711	298,770,235
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	3,796,793,711	298,770,235

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
2,297			34,665,687		48
21,264			41,274,219		49
2,099,126			286,101,340		50
64,506			136,921,634		51
555,010			93,136,953		52
802,568			150,452,740		53
					54
					55
			318,351		56
					57
3,544,771			742,870,924		58
					59
5,593			4,715,078		60
27,667			24,515,065		61
306,213			167,223,999		62
					63
2,050,267			210,585,863		64
1,522,602			116,789,867		65
65,918			47,417,198		66
556,861			179,509,673		67
6,008,815			381,826,912		68
429,602			55,557,765		69
970,061			58,984,822		70
351,216			2,536,798		71
					72
57,435			4,152,933		73
			232,370		74
12,352,250			1,254,048,343		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			10,828,375		86
484,603			71,404,395		87
3,876,887			45,904,852		88
4,459,265			58,431,918		89
28,843			1,182,487		90
172,987			4,808,712		91
430,282			10,712,475		92
345,591			8,673,751		93
1,242,638			26,110,806		94
154,185			4,106,221		95
11,195,281			242,163,992		96
					97
					98
11,195,281			242,163,992		99
64,975,598			4,030,588,348		100
					101
					102
					103
64,975,598			4,030,588,348		104

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Boise Operations Center	12/31/82		768,377
3	Production			112,703
4	Transmission Stations			429,822
5	Transmission Lines			68,619
6	Distribution Stations			1,157,999
7	Beacon Light Substation (1)	12/30/02		465,662
8	Homedale Substation	2/29/08		109,453
9	North River Operations Center	1/31/08		2,630,412
10	Boise Operations Center	12/31/82		72,785
11	Boise Mechanical and Electrical Shop	12/31/01		47,000
12	Transmission Stations	12/31/81		178,094
13	Distribution Stations			61,518
14	Homedale Substation	2/29/08		215,719
15				
16				
17				
18				
19	Column B if no date listed it is various			
20				
21	Other Property:			
22				
23				
24				
25				
26				
27	(1) a portion of Beacon Light was classified in			
28	account 101000 in the prior year. In 2007 it			
29	was reclassified to account 105000.			
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			6,318,163

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/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	ROLLUP RELIC COST BROWNLEE	40,342,807
2	ROLLUP RELIC COST HELLS CANYON	27,627,540
3	ROLLUP RELIC COST OXBOW	12,682,103
4	HELLS CANYON RELICENSING OUTSI	9,430,117
5	VALMY UNDISTRIBUTED WORK ORDER	6,137,283
6	CIAC LIABILITY RECLASS	6,022,349
7	CAPITALIZE RENEWED R/W CONTRAC	5,901,983
8	TURBINE BLADES AND VANES - CAP	5,879,617
9	DNPR0601 OPERATIONS	4,696,909
10	BRIDGER UNDISTRIBUTED WORK ORD	4,144,315
11	NEW OPERATIONS CENTER @ LAKE F	3,898,514
12	HUBBARD NEW 230 KV SWITCHING S	3,881,974
13	GATEWAY WEST 500KV LINE	3,686,522
14	WQ - ONGOING HELLS CANYON RELI	3,276,768
15	IPCO*CONVERT HAVN TO 138 KV	2,527,819
16	MPSN - MIDPOINT EAST RAS UPGRA	2,039,604
17	BRIDGER 2007C207 U3 SO2 EMIS C	1,917,087
18	HCC RELICENSING FISH2004 FEASI	1,870,234
19	BOARDMAN - HEMINGWAY 500 KV LI	1,848,052
20	JIM BRIDGER RAS-A AND RAS-B	1,711,403
21	REL-HELLS CANYON COMPLEX FY200	1,618,941
22	CJ STRIKE: #1 TURBINE RUNNER	1,551,344
23	HMWY - BUILD HEMINGWAY 500/230	1,474,063
24	ETGT0703 - INCREASE T132 AND R	1,395,188
25	342 COST CENTER DELIVERY CAPIT	1,366,017
26	BRIDGER 2007C189 U1 SO2 EMIS C	1,364,664
27	IPCO*UPGRADE PNGE TO FACILITAT	1,289,859
28	HCC RELICENSING, FISH2004 INST	1,269,901
29	COST CENTER 317 DELIVERY CAPIT	1,228,396
30	HCC RELICENSING, FISH2004 REDB	1,136,664
31	HCC RELICENSING, FISH2004 ANAD	1,123,075
32	WEB SITE REDESIGN	1,103,510
33	ROLLUP RELIC COST SWAN FALLS	1,088,739
34	CAPITAL REGION CONVERSION TO A	1,021,319
35	SWAN FALLS RELICENSING	1,012,279
36	PAYROLL & IBNR ACCRUAL	896,085
37	RIVER ENG.-HELLS CANYON CONTIN	862,986
38	326-COST CENTER DELIVERY CAPIT	856,664
39	BROWNLEE LOCAL SERVICE UPGRADE	854,703
40	BRIDGER 2007C812 SODA LIQUOR S	835,409
41	BRIDGER 2008C102 U1 GENERATOR	831,690
42	BRIDGER 2008C123 U1 TURBIN UPG	831,529
43	TOTAL	207,662,162

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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	REL-HCC OREGON REAUTHORIZATION	811,243
2	BRIDGER 2007C191 U2 SO2 EMIS C	808,892
3	LEGAL DEPT. LABOR FOR RELICENS	765,891
4	PURCHASE #4 TURBINE RUNNER	750,479
5	BUILD NEW ADRIAN SUBSTATION AT	700,142
6	T7230701 OPGW DANSKIN-HUBBARD	646,583
7	341 COST CENTER DELIVERY CAPIT	627,577
8	418-CC DELIVERY CAPITAL OVERHE	626,271
9	392 COST CENTER DELIVERY CAPIT	613,484
10	REL - SWAN FALLS FY2004 CAPITA	606,870
11	577 COST CENTER DELIVERY CAPIT	601,961
12	HCC RELICENSING FISH2004 RESID	597,977
13	BRIDGER 2007C206 FAN BAY ROAD	594,137
14	578 COST CENTER DELIVERY CAPIT	576,076
15	BRIDGER 2008C090 U2 REHEATER O	558,488
16	CONSTRUCTION ACCOUNTING CAPITA	555,252
17	VALMY 98208581 U2 GENERATOR RE	549,524
18	ST LUKES MVRMC-POLELINE & GRAN	548,850
19	BEACON LIGHT SITE WORK, FENCE,	546,198
20	343 COST CENTER DELIVERY CAPIT	539,718
21	415-CC DELIVERY CAPITAL OVERHE	537,081
22	VALMY 98210178 INSTALL PRODUCT	536,698
23	PHASE 2 AMI- AMI METER CONTRAC	519,319
24	LINE 438, PERMITTING & ROW FOR	502,933
25	335-COST CENTER DELIVERY CAPIT	497,948
26	IPCO*LINE #446 PNGE-HAVN CONVE	496,813
27	390 COST CENTER DELIVERY CAPIT	489,938
28	BOISE PLAZA LEASE	483,484
29	GEN PCB & METAL CLAD REPLACEME	464,011
30	WQ SWAN FALLS RELICENSING-CAPI	456,204
31	CAPITAL (DELOVHD)	409,378
32	COST CENTER 316 DELIVERY CAPIT	408,250
33	ROW FOR T404 - 138 KV TO CHERR	403,191
34	REC - BAKER COUNTY SETTLEMENT	399,000
35	BEARING COOLERS, CLOSED LOOP S	398,296
36	455-COST CENTER DELIVERY CAPIT	391,956
37	336-COST CENTER DELIVERY CAPIT	384,627
38	IPCO/HBND-041 REBUILD APPROX 3	382,574
39	CHQ 5 REMODEL FURNITURE	382,499
40	MORA-042 FEEDER WORK 8.5 MILES	369,495
41	IT SERVICE MANAGEMENT SOFTWARE	366,317
42	BRIDGER 2007C911 PLANT SECURIT	357,206
43	TOTAL	207,662,162

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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	HAILEY TEAM CAP OH WORK ORDER	356,095
2	ACCUFILE TAX APPLICATION REPLA	355,949
3	TERR: HCC RELICENSING	348,234
4	WYE ADD AMI EQUIPMENT	346,218
5	ENHANCED LAW ENFORCEMENT PER S	338,654
6	DELIVERY WORK ORDER RECON PROJ	334,767
7	381 -COST CENTER DELIVERY CAPI	327,484
8	IPCO-CITY OF KETCHUM/IMPROVE L	325,980
9	EEM SOFTWARE	323,552
10	575 COST CENTER DELIVERY CAPIT	317,440
11	MORA STATION MODIFICATIONS AS	317,185
12	CHQ 5 REMODEL	309,169
13	LINE 438, RIGHT OF WAY, VICTOR	305,769
14	REPLACE POWER CENTERS ON PLANT	303,233
15	GOODING TEAM CAP OH WORK ORDER	295,304
16	BOARDMAN 24554 REWIND GENERATO	289,783
17	ORACLE SOA HARDWARE	285,354
18	VALMY 98218173 U2 PULVERIZER U	284,506
19	BORA0501 BORA-MPSN 345KV THER	284,156
20	SWAN FALLS RELICENSING FISH200	279,719
21	153 COST CENTER DELIVERY CAPIT	278,675
22	T7110401-HPVY 230KV DOUBLE CIR	276,036
23	IPCO/BOIS-021/2006 DOWNTOWN CA	273,479
24	REL - REC SWAN FALLS RELICENSI	272,926
25	AFTS0701 - REPL 11 AB SWITCHES	270,821
26	Delivery Overheads	269,832
27	ENTERPRISE CONTENT MANAGEMENT	262,521
28	NEW RESTROOM, SEWER AND WATER	261,809
29	ORACLE SOA SUITE	260,683
30	TWINWEST TEAM CAP OH WORK ORDE	248,465
31	BRIDGER 2007C706 FLYASH LOADIN	247,796
32	USTICK ADD AMI EQUIPMENT	247,397
33	BRIDGER 2008C064 U2 EXCITATION	246,837
34	ADAMSFAM TEAM CAP OH WORK ORDE	243,434
35	100-COST CENTER DELIVERY CAPIT	242,489
36	IPCO*PERMIT / PURCHASE ROW FOR	239,462
37	334-COST CENTER DELIVERY CAPIT	239,178
38	TFSN015 REPLACE GETAWAY CABLE	238,735
39	REBUILD ADEL 301A---COMPLETE/L	236,375
40	STATE ADD AMI EQUIPMENT	230,599
41	AMI IT SOFTWARE	229,387
42	BRIDGER 2007C213 SOOT BLOWER C	226,467
43	TOTAL	207,662,162

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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	410-CC DELIVERY CAPITAL OVERHE	224,597
2	324-COST CENTER DELIVERY CAPIT	219,865
3	NERC CRITICAL INFRASTRUCTURE P	219,689
4	STATIC EXCITER #1 UNIT (PURCHA	213,901
5	TFEAST TEAM CAP OH WORK ORDER	212,709
6	COST CENTER 310 DELIVERY CAPIT	211,663
7	BOARDMAN 24226 PURCH SPARE GEN	211,424
8	BRIDGER 2008C124 U1 REHEATER R	211,390
9	LONG VALLEY OPERATION CENTER F	210,867
10	FRMT0701 - REPLACE 131H WITH A	206,403
11	REL - REC HCC RELICENSING PROC	200,927
12	585 COST CENTER DELIVERY CAPIT	199,318
13	SUPERVALU DATA CENTER- ON-SITE	199,196
14	PQ IR CAMERAS	197,232
15	420-CC DELIVERY CAPITAL OVERHE	196,739
16	BORA: RAS C & D COMMUNICATIONS	196,248
17	375 COST CENTER DELIVERY-CAPIT	196,090
18	HOMESTEAD ROAD WORK ASSOCIATED	194,725
19	JIM BRIDGER SUBSTATION CAPITAL	193,255
20	404 COST CENTER DELIVERY CAPIT	193,143
21	TOOL EXP TRANS TO CONST	188,428
22	DELIVERY CAPITAL OVERHEADS FOR	187,992
23	MINI CASSIA TEAM CAP OH WORK O	186,042
24	SEMINIS VEG SEED-1811 E FLORID	185,853
25	CROSS ARM CHANGE OUT BUBG-42	183,333
26	IPCO- RELIBALITYAND MAINTENANC	182,569
27	IPCO*INSTALL 69 KV LINE TERMIN	181,876
28	COST CENTER 329 DELIVERY CAPIT	177,157
29	378 -COST CENTER DELIVERY CAPI	176,180
30	WATER RIGHTS ACQUISITION: COT	175,958
31	FALL CHINOOK POPULATION VIABIL	175,699
32	KENNISON DAIRY CONDUCTOR UPGRA	173,236
33	RE-ROUTE BOBN-CDWL 230KV TO H	170,851
34	DESIGN, BUILD, INSTALL UNIT #2	167,933
35	L-252, GOLDEN VALLEY LOOP, PAT	163,911
36	BEACON LIGHT 138-KV TAP-PERMIT	158,814
37	IPCO/ CDAL 015/ F42/ 2008 CABL	158,711
38	300 COST CENTER DELIVERY CAPIT	158,427
39	BRIDGER 2008C085 U4 SO2 & PM E	158,282
40	BRIDGER 2008C049 U4 OVATION CO	157,601
41	BRIDGER 2008C117 U1 APH BASKET	156,537
42	MPSN: RAS C & D COMMUNICATIONS	156,245
43	TOTAL	207,662,162

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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	856 COST CENTER DELIVERY CAPIT	156,118
2	**INSTALL COMMUNICATIONS FROM	155,482
3	353 COST CENTER DELIVERY CAPIT	154,802
4	COST CENTER 318 DELIVERY CAPIT	153,797
5	IPCO/ GARY 011/ F32/ 2008 CABL	153,152
6	CALL CENTER LABOR HOURS FOR LI	152,823
7	AGING INFRASTRUCTURE TOOL INTE	152,014
8	IPCO- RELIABLITY WOOD PIN REPL	148,964
9	IPCO/ITD CITY OF DONNELLY RO	148,227
10	PQ ENGINEERS & TECH TEAM 2008	147,030
11	IPCO- PICABO MOUNTAIN/ REPLACE	145,697
12	CARO-012 REBUILD-2.5 MILES-TO	145,327
13	#2 PURCHASE STATIC EXCITATION	142,008
14	VALMY 98219937 PA FAN CAPITAL	141,713
15	AMI EQUIPMENT @ GROVE SUBSTATI	140,711
16	MORA0602 - COMMUNICATIONS UPGR	140,621
17	T7250801 HMWY-BOMT DBL CRT 230	140,007
18	GOODING RURAL ADD T052 TRANSFO	138,761
19	L-210, BOBN-GFRY 69KV, PATROL	138,699
20	BORA 304A BREAKER REPLACEMENT	136,838
21	KINPORT: RAS C & D COMMUNICATI	136,025
22	IPCO/IDOT KEY#8743 7TH AVE. NO	134,437
23	458-COST CENTER DELIVERY CAPIT	134,171
24	356 COST CENTER DELIVERY CAPIT	133,413
25	PURCHASE AND IMPLEMENT SYNERGE	133,247
26	2008 TEST EQUIPMENT-CAPITAL	132,041
27	CCTV STANDARDIZATION PROJECT-P	131,249
28	579 COST CENTER DELIVERY CAPIT	130,607
29	210-COST CENTER DELIVERY CAPIT	130,605
30	IPCO/ MOVE FACILITIES FROM 17T	129,796
31	584 COST CENTER DELIVERY CAPIT	127,392
32	LNSG-EXPAND YARD & LANDSCAPE	126,623
33	IPCO- DIXI031 FDR RLBLTY / R17	125,826
34	BRIDGER 2008C042 BCP MOTOR REW	124,923
35	VALMY 98211919 U1 BOTTOM ASH P	121,109
36	377 -COST CENTER DELIVERY CAPI	120,452
37	TFSB PARKING & TRANSFORMER STO	120,293
38	AFTS0501 AFTS-MDKA THERMAL DE	116,417
39	HILL INSTALL T132, CKT SWITCHE	114,532
40	BRIDGER 2008C069 VIBRATION MON	113,956
41	HYDA-UPGRADE PORTABLE TRANSFOR	113,557
42	AMI EQUIPMENT @ GARY SUBSTATIO	112,534
43	TOTAL	207,662,162

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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	PURCHASE & INSTALL DIESEL BACK	111,926
2	AMI EQUIPMENT @ EKRT	107,691
3	DNPR0602 COMMUNICATION UPGRADE	107,541
4	IPCO/BOBN-044/F-137/2007 CABLE	107,038
5	APPARATUS SERVER --- HARDWARE	106,863
6	BRIDGER 2007C209 U4 SO2 EMIS C	105,134
7	EMET0701 REPLACE T132	104,433
8	KENNISON DAIRY CONDUCTOR UPGRA	104,308
9	WILS-WGNR 138 KV LINE ROW LINE	103,511
10	VALMY 98200467 REPL COAL BELTS	103,221
11	CANYON REGION MANAGER LABOR AN	102,694
12	1998 NEAR EAST IDAHO VESTED I	101,493
13	LINE 328 WARM LAKE TAP REPAIR	100,598
14	345 COST CENTER DELIVERY CAPIT	100,556
15	OTHER MINOR PROJECTS	-16,062,667
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43	TOTAL	207,662,162

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/Q4

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

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

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	1,430,468,593	1,430,468,593		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	96,637,583	96,637,583		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	3,111,243	3,111,243		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9	Fuel Stock	113,509	113,509		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	99,862,335	99,862,335		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	39,512,878	39,512,878		
13	Cost of Removal	8,438,450	8,438,450		
14	Salvage (Credit)	5,435,743	5,435,743		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	42,515,585	42,515,585		
16	Other Debit or Cr. Items (Describe, details in footnote):	-1,064,253	-1,064,253		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,486,751,090	1,486,751,090		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	442,070,073	442,070,073		
21	Nuclear Production				
22	Hydraulic Production-Conventional	264,025,839	264,025,839		
23	Hydraulic Production-Pumped Storage				
24	Other Production	17,474,253	17,474,253		
25	Transmission	230,292,212	230,292,212		
26	Distribution	441,040,082	441,040,082		
27	Regional Transmission and Market Operation				
28	General	91,848,631	91,848,631		
29	TOTAL (Enter Total of lines 20 thru 28)	1,486,751,090	1,486,751,090		

Schedule Page: 219 Line No.: 14 Column: c

Relocation reimbursements, Up and down costs and damage insurance claims $720,911

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

Accumulated Provision for Depreciation on Asset Retirement Obligation	$	459,618
Embedded removal in Accumulated provision for Depreciation		(1,523,871)
	$	(1,064,253)

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	Idaho Energy Resources Company			
2	Common Stock	02/01/74		500
3	Capital contributions			2,462,594
4	Equity in earnings			53,474,013
5				
6	Subtotal Idaho Energy Resources Company			55,937,107
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42	Total Cost of Account 123.1 $ 2,463,094		TOTAL	55,937,107

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/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
		500		2
		2,462,594		3
4,121,080		57,595,093		4
				5
4,121,080		60,058,187		6
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4,121,080		60,058,187		42

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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)	17,267,629	16,851,868	Electric
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)			
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	12,737,352	13,785,883	
8	Transmission Plant (Estimated)	9,429,545	9,182,847	
9	Distribution Plant (Estimated)	18,595,934	20,839,000	
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	607,920	597,997	
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	41,370,751	44,405,727	Electric
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)	1,898,952	5,715,442	Electric
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	60,537,332	66,973,037	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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	Balance at Beginning of Current Quarter/Year	Debits	CREDITS		Balance at end of Current Quarter/Year
				Written off During the Quarter/Year Account Charged	Written off During the Period Amount	
	(a)	(b)	(c)	(d)	(e)	(f)
1	Idaho DSM Rider - IPUC Order #29026		7,188,545	254	3,246,227	3,942,318
2						
3	Fixed Cost Adjusment (FCA) Order #30267		4,657,142	254	1,935,924	2,721,218
4						
5	IPUC Grid West loans - IPUC order #30157	745,742		401	186,435	559,307
6	(amort period 1/07 - 12/11)					
7						
8	FERC Grid West Expense	302,117	116,877	401	55,878	363,116
9	FERC Docket #AC03-78-000					
10						
11	Oregon PCAM Def order 08-238		5,399,657			5,399,657
12						
13	Asset Retirment Obligations - IPUC	12,188,065	928,016	230	2,209,539	10,906,542
14	Order #29414 - OPUC Order #04-585					
15						
16	LT & ST Mark to Market	171,234	4,028,601	244	1,126,205	3,073,630
17						
18	Fin 48 Unfunded-Noncurrent-IPUC Order 29601	(37,067,740)	38,800,873	282	8,903,384	-7,170,251
19						
20	Regulatory Unfunded Accumulated Deferred Income Tax	357,913,795	166,572,965	See Note	14,407,255	510,079,505
21						
22	PCA Deferral Idaho - IPUC order 30047	85,731,733	170,950,587	See Note	163,025,112	93,657,208
23	(amort period 6/08 thru 5/09)					
24						
25	Prior Year PCA - Idaho - IPUC order 30325	6,590,536	127,508,162	401	86,934,777	47,163,921
26	(amort period 6/07 thru 5/08)					
27						
28	Idaho - Demand Side Management - IPUC order	8,106,539		401	3,242,604	4,863,935
29	#27660 (amort period 7/98 thru 6/10)					
30						
31	Excess Power Deferral 06/07 - IPUC order	2,106,816	2,194,558	254	3,086,676	1,214,698
32	07-555					
33						
34	Excess Power Amortization - OPUC Order#06-070	2,992,604	2,010,010	See Note	3,339,341	1,663,273
35	(Capped at 10% per year until full amort)					
36						
37	Security Costs 2003 - IPUC Order #28975	68,794		401	68,794	
38	(amort period 1/04 - 12/08)					
39						
40	OPUC Grid West Loans - OPUC Order #06-483	60,407	4,588			64,995
41						
42	Unfunded SFAS 106 Lia 30256 - IPUC Order #30256	8,006,409	12,464,601	228	1,567,074	18,903,936
43						
44	TOTAL	448,227,917	542,905,448		293,488,641	697,644,724

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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	PS & I Coal Plant - Order #29904	235,859		401	85,767	150,092
2	(amort period 10/2007 thru 9/10)					
3						
4	Minor items(7)	75,007	80,266	various	67,649	87,624
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42						
43						
44	TOTAL	448,227,917	542,905,448		293,488,641	697,644,724

Schedule Page: 232 Line No.: 20 Column: d

Account	228	$ 703,807
Account	282	13,638,348
Account	401	65,100
Total		$ 14,407,255

Schedule Page: 232 Line No.: 22 Column: d

Account	182	$ 124,101,211
Account	254	23,264,092
Account	401	15,659,809
Total		$ 163,025,112

Schedule Page: 232 Line No.: 34 Column: d

Account	254	$ 898,486
Account	401	2,440,855
Total		$ 3,339,341

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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	Rents - Rights of way		137,573			137,573
2						
3	2008 Poll Control Bond Refin		169,409	131	8,328	161,081
4						
5	Advance prepaid coal royalties	1,657,049		131	76,533	1,580,516
6						
7	Security plan	25,920,430	2,537,506	165&426	3,704,186	24,753,750
8						
9	American Falls bond refinance	249,814		401	14,552	235,262
10	(amort period 4/00 thru 7/26)					
11						
12	Prepaid Credit Facility	640,032		431	193,597	446,435
13						
14	Company owned Life Insurance	4,921,300	1,193,489	426	1,386,274	4,728,515
15						
16	American Falls water rights	17,800,983		401	1,042,009	16,758,974
17	(amort period 1/06 thru 12/25					
18						
19	Milner bond guarantee	11,700,000	1,063,636	253	3,190,909	9,572,727
20						
21	Southwest intertie project -	6,417,011		253	3,465,186	2,951,825
22	right of way costs					
23						
24	CSPP receivable	270,767	2,460	143	273,227	
25						
26	American Falls - bond refinance	823,985		401	47,999	775,986
27	(35 year amortization)					
28						
29	Shelf Registration - 2008	144,517	1,500,608	181	1,645,125	
30						
31	Transmission Deposit-PacifiCorp	2,354,100	525,000	131	2,217,225	661,875
32						
33	Prepaid Peoplesoft/Passport	51,343	156,671	401	73,808	134,206
34						
35	Valmy Power Plant	260,973	480,250	various	731,276	9,947
36						
37	Boardman Power Plant		149,444			149,444
38						
39	Minor Items & Job Orders (8)	9,879	33,526	Various	41,717	1,688
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	73,222,183				63,059,804

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			
3	Emission Allowances	6,920,940	-3,114,188
4	Advances for Construction	10,171,997	9,305,479
5	Other Electric (See footnote)	16,363,769	21,074,809
6			
7	Other (See footnote)	57,716,499	122,738,456
8	TOTAL Electric (Enter Total of lines 2 thru 7)	91,173,205	150,004,556
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other Non Electric See footnote	14,873,945	17,642,299
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	106,047,150	167,646,855

Notes

Schedule Page: 234 Line No.: 5 Column: a

(Note 1):	Ending Balance	Ending Balance
Post Retiree Benefits-VEBA	4,056,404.55	4,929,292.29
Rate Case Disallowance	3,112,707.91	2,996,869.81
Other Employee's Long Term Deferred Compensation	2,590,725.18	1,829,071.70
IRS Interest Expense	2,148,245.00	2,090,777.00
FAS 123R - Stock Based Compensation	1,333,711.47	2,316,810.74
SFAS112 - Post Retirement Benefits	1,184,641.05	1,044,455.76
Provision For Rate Refunds	937,172.05	5,217,171.07
Non-VEBA Pension and Benefits	762,810.30	662,313.05
Linden Feeder Deposits	164,403.47	0.00
Delivery Accruals	129,130.02	(5,646.49)
Bonus Deferral	(56,181.86)	(6,306.02)
Total Other Electric	16,363,769.14	21,074,808.91

Schedule Page: 234 Line No.: 7 Column: a

(Note 2):	Beginning Balance	Ending Balance
FASB 109 Accounting	42,967,558.09	44,340,912.95
FAS 158 - Pension	3,815,137.55	61,943,744.74
FAS 158 - Postretirement Plan	6,616,913.51	10,863,821.80
Minimum Pension Liability	4,316,889.45	5,589,976.57
Total Other	57,716,498.60	122,738,456.06

Schedule Page: 234 Line No.: 17 Column: a

(Note 3):	Beginning Balance	Ending Balance
Senior Management Security Plan	12,554,517.13	12,912,429.52
FAS115 SMSP Impairment	0.00	2,669,975.82
Micron-CIAC	2,001,223.02	1,764,125.52
Meridian Gold Contributions	174,791.41	152,678.89
Bridger Sierra Reserve-Legal Fee's	97,737.50	97,737.50
Loss on Pioneer Land Write-down	45,351.37	45,351.37
Seattle City Light-CIAC	324.49	0.00
Total Non Electric	14,873,944.92	17,642,298.62

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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			
2	Common Stock registered on New York	50,000,000	2.50	
3	and Pacific Stock Exchange			
4	Total Common Stock	50,000,000	2.50	
5				
6	Account 204 - None			
7				
8				
9				
10				
11				
12				
13				
14				
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CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
39,150,812	97,877,030					2
						3
39,150,812	97,877,030					4
						5
						6
						7
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/Q4

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

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

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

(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.

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

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

Line No.	Item (a)	Amount (b)
1	Account 208 - Donations received from stockholders	
2		
3	Account 209 - Reduction in par or stated value of Capital Stock	
4		
5	Account 210 - Gain on reacquired Capital Stock	
6		
7		
8	Account 211 - Miscellaneous paid-in Capital	
9		
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38		
40	TOTAL	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/Q4

CAPITAL STOCK EXPENSE (Account 214)

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

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Stock	2,096,925
2		
3		
4		
5		
6		
7		
8		
9		
10	Explanation of Changes during the year:	
11		
12		
13		
14		
15		
16		
17		
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19		
20		
21		
22	TOTAL	2,096,925

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/Q4

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Account 221:		
2	First Mortgage Bonds:		
3	5.50% Series due 2033	70,000,000	728,701
4			36,400 D
5			
6	7.38% Series Due 2007	80,000,000	
7			
8	7.20% Series due 2009	80,000,000	572,246
9			
10	5.30% Series Due 2035	60,000,000	408,411 D
11			3,844,739
12			
13	6.60% Series due 2011	120,000,000	860,502
14			
15	4.25%Series due 2013	70,000,000	641,201
16			374,500 D
17			
18	4.75% Series due 2012	100,000,000	944,356
19			1,047,617 D
20			
21	6.00% Series due 2032	100,000,000	1,069,356
22			543,244 D
23			
24	5.875% Series due 2034	55,000,000	585,759
25			383,322 D
26			
27	5.50% Series due 2034	50,000,000	746,961 D
28			524,419
29			
30	6.30% Series due 2037		1,495,799
31			273,721 D
32			
33	TOTAL	987,045,000	21,296,747

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
						2
05/01/03	04/01/33	05/01/03	03/31/33	70,000,000	3,850,000	3
						4
						5
12/1/00	12/01/07	12/01/00	12/01/07		-27,510	6
						7
11/23/99	12/01/09	01/01/00	01/01/10	80,000,000	5,760,000	8
						9
08/26/05	08/26/35	08/26/05	08/26/35	60,000,000	3,180,000	10
						11
						12
03/02/01	03/02/11	03/02/01	03/02/11	120,000,000	7,920,000	13
						14
05/01/03	10/01/13	05/01/03	09/29/13	70,000,000	2,975,000	15
						16
						17
11/15/02	11/15/12	11/15/02	11/15/12	100,000,000	4,750,000	18
						19
						20
11/15/02	11/15/32	11/15/02	11/15/32	100,000,000	6,000,000	21
						22
						23
08/16/04	08/16/34	08/16/04	08/16/34	55,000,000	3,231,250	24
						25
						26
03/26/04	03/15/34	03/26/04	03/15/34	50,000,000	2,750,000	27
						28
						29
6/22/07	6/15/2037	6/22/07	6/15/2037	140,000,000	8,820,000	30
						31
						32
				1,264,917,727	66,145,498	33

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/Q4

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	6.25% Series due 2037		1,141,489
2			266,188 D
3			
4	Port of Morrow Variable due 2027	4,360,000	188,545
5			
6	Humboldt Variable due 2024	49,800,000	1,697,856
7			
8	Sweetwater Variable due 2026	116,300,000	820,043
9			471,252 D
10			
11	6.025 % Series Due 2018 OPUC 08-105 IPUC #30487		1,630,120
12			
13	2008 Credit Facility OPUC 07-151 IPUC #30294		
14	Subtotal Account 221	955,460,000	21,296,747
15			
16	Account 222 - Reaquired Bonds		
17	Humbolt PC Revenue		
18			
19	Sweetwater PC Revenue		
20	Subtotal Account 222		
21			
22	Account 223: Advances for Associated Companies		
23			
24	Account 224:		
25	Bond Guarantee - American Falls	19,885,000	
26			
27	REA Notes		
28			
29	Note Guarantee - Milner Dam	11,700,000	
30	Subtotal Account 224	31,585,000	
31			
32			
33	TOTAL	987,045,000	21,296,747

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/Q4

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
10/18/07	10/15/2037	10/18/07	10/15/2037	100,000,000	6,250,000	1
						2
						3
05/17/00	02/01/27	05/17/00	02/01/27	4,360,000	135,091	4
						5
10/22/03	12/01/24	11/01/03	12/01/24	49,800,000	693,790	6
						7
10/3/06	7/15/26	10/3/06	7/15/2026	116,300,000	2,030,166	8
						9
						10
7/10/08	7/15/18	7/10/08	7/15/08	120,000,000	3,434,250	11
						12
4/1/08	3/31/09	4/1/08	3/31/09	166,100,000	4,393,600	13
				1,401,560,000	66,145,637	14
						15
						16
				-49,800,000		17
						18
				-116,300,000		19
				-166,100,000		20
						21
						22
						23
						24
04/26/00	2/1/25			19,885,000		25
						26
					-139	27
						28
02/10/92				9,572,727		29
				29,457,727	-139	30
						31
						32
				1,264,917,727	66,145,498	33

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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)	94,114,928
2		
3		
4	Taxable Income Not Reported on Books	
5		68,986,908
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		23,313,008
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		3,804,846
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		58,362,619
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	77,621,363
28	Show Computation of Tax:	
29	Tenative Federal Tax @ 35%	27,167,477
30		
31		
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Schedule Page: 261 Line No.: 5 Column: b

004003-CONSTRUCTION ADV-252	(2,475,768)
004004-CIAC AS TAXABLE INC CLOSED TO PLANT	29,000,000
004005-AVOIDED COST INT CAP	4,940,208
004006-RETIREMENTS-RECORD TAX GAIN/LOSS	(2,000,000)
004010-EMISSION ALLOWANCE-254.409-411	40,669,016
004013-CIAC AS TAXABLE INC IN ACCT 107	(1,063,720)
004018-LINDEN FEEDER DEPOSITS-253.206	(420,523)
004020-ENGINEERING FEES-CLOSED TO PLANT	1,620,274
004021-ENGINEERING FEES-IN ACCT 107-FED ONLY	(716,724)
004501-ROYALTY INCOME BTL	100,000
004506-CIAC-MERIDIAN GOLD	(56,560)
004507-CIAC-MICRON-DRAM	(608,469)
004512-CIAC-SEATTLE CITY LIGHT	(826)
Total	**68,986,908**

Schedule Page: 261 Line No.: 10 Column: b

005001-BAD DEBT EXPENSE	418,877
005010-SFAS 112-POST-EMPLY BEN 182/253	(358,576)
005014-OVERACCRUED VACATION-ACCT 242	257,944
005017-INJURIES & DAMAGES	1,253,352
005019-DIRECTORS FEES DEF	(27,556)
005022-CAPITALIZED OVERHEADS	(12,000,000)
005024-MEALS (50% NON-DEDUCTIBLE) CHRGD TO R.E.	600,000
005025-MILNER FALLING WATER - REV ACCRL	(619,723)
005027-AMORTIZATION OF ACCOUNT 114	(22,723)
005028-OREGON OPER PROPERTY TAX ADJ	(37,557)
005033-NONVEBA PEN&BEN-Acct 228	(257,059)
005035-PCA EXPENSE DEFERRAL	(51,056,694)
005043-AMERICAN FALLS - FALLING WATER CONTRACT-FT	219,181
005047-OTHER EMPLOYEE'S LT DEFERRED COMP-228	(1,948,212)
005050-186-BAD DEBT RESERVE-FINANCING PRGMS	(4,461)
005052-AMORTIZATION OF ACCOUNT 181	140,900
005053-FAS 123R-STOCK BASED COMPENSATION	2,542,842
005054-IPUC GRID WEST LOANS-ACCT 182	186,435
005055-OPUC GRID WEST LOANS-ACCT 182	(4,588)
005056-FERC GRID WEST EXP-ACCT 182	(61,000)
005057-INTERVENER FUNDING ORDERS-ACCT 182	(24,703)
005058-FIXED COST ADJUSTMENT (FCA)-ACCT 182	(3,761,843)
005059-PS & I COSTS-COAL & CHP PLANTS-WRITE OFF	97,853
005060-OREGON-PCAM (POWER COST ADJ MECHANISM)	(5,399,657)
005501-SEC PLAN-NET INS COSTS	(302,480)
005503-128-EDC-UNRLZD GN/LS FRM RABBI TRUST	1,141,566
005504-NONDEDUCTIBLE POLITICAL EXP-426.4	1,273,314
005505-SEC PLAN-BENEFIT ACCR	1,983,519
005516-NONDEDUCTIBLE POLITICAL EXP-O&M ACCTS	100,000
005531-RATE CASE DISALLOWANCES-REVERSE AMORT	(296,299)
005532-DELIVERY ACCRUALS-253.550	(91,775)
005539-FAS115 SMSP IMPAIRMENT	6,829,456
Total	**(23,313,008)**

Schedule Page: 261 Line No.: 15 Column: b

007009-PROVISION FOR RATE REFUNDS-ACCT 229	(10,947,688)
007501-REVERSE EQUITY EARNINGS OF SUBSIDIARIES	4,121,080
007502-ALLOWANCE FOR OFUDC	3,141,017
007503-ALLOWANCE FOR BFUDC	7,080,140
007509-SECURITY PLAN-INSURANCE PROCEEDS	628,234
007514-COLI-INSURANCE PROCEEDS	170,651
007518-IRS INTEREST INCOME	(388,588)
Total	**3,804,846**

Schedule Page: 261 Line No.: 20 Column: b

008001-VEBA-POST RET BNFTS-TRUST-ACCT 228	(2,232,734)
008009-DEPR FOR TAX GT OR LT BOOK	44,604,054
008016-VEBA-POST RET BNFTS-TRUST-MEDICARE PART D	646,000
008020-CONSERVATION PROGRAMS	(3,242,604)
008025-MANUFACTURING DEDUCTION	1,726,426
008027-NEVADA OPERATING PROPERTY TAX ADJ	24,642
008034-REMOVAL COSTS	8,439,209
008035-REPAIR ALLOWANCE	7,000,000
008038-OREGON EXCESS PWR SUPPLY COSTS	(1,158,317)
008039-ST TAX-NOT DEDUCTED ON PRIOR RETURN	(13,168)
008041-AM FALLS - UNAMORTIZED DEBT EXP	(47,999)
008042-GAIN/LOSS ON REACQUIRED DEBT-FT	(707,798)
008059-SFTWR COSTS-MISC-107-FED ONLY	1,000,000
008072-INTANGIBLE ASSET-LABOR DEDUCT-107-FED ONLY	2,532,000
008074-INCREMENTAL SECURITY COSTS DEDUCTED	(68,794)
008077-PP INS & OTR EXP (1 YR OR LESS)-165	856,870
008501-COLI-TAX ADJ FROM BOOKS	(186,662)
008504-OREGON NONOP PROPERTY TAX ADJUST	35
008508-DEPR ADJ - NONOP - OTHER PROPERTY - NEW	(326,269)
008703-IPCO - 162 (M) $1m THRESHOLD	(674,346)
0NI0016-DIV PAID DED PUB UTIL	300,000
IRS INTEREST EXPENSE	**146,994**
STATE INCOME TAX DEDUCTED ON FEDERAL RETURN	**(254,920)**
Total	**58,362,619**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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	-2,776,064		-5,158,387	36,345,148	
3	Social Security - (FOAB)	417,170		11,476,651	11,893,412	
4	Unemployment	43,023		124,895	167,954	
5	Subtotal Federal	-2,315,871		6,443,159	48,406,514	
6						
7	State of Idaho:					
8	Property	5,703,852	225	10,969,659	11,694,806	
9	Non-Operating	15,963		29,992	30,959	
10	Income	-1,461,670		-3,790,374	-1,454,044	
11	KWH	300,717		1,559,972	1,765,494	
12	Unemployment	19,721		175,196	188,713	
13	Regulatory Commission			1,728,039	1,728,039	
14	Business License - Sho Ban		150	150	150	
15	Subtotal Idaho	4,578,583	375	10,672,634	13,954,117	
16						
17	State of Oregon					
18	Property		1,007,104	2,052,307	2,089,865	
19	Non-Operating Property		719	1,473	1,508	
20	Income	-66,941		118,545	264,053	
21	Regulatory Commission			119,843	119,843	
22	Unemployment	899		12,554	13,467	
23	Franchise	125,213		541,650	529,157	
24	Subtotal Oregon	59,171	1,007,823	2,846,372	3,017,893	
25						
26	State of Montana:					
27	Property	46,418		198,721	146,009	
28	Subtotal Montana	46,418		198,721	146,009	
29						
30	State of Nevada:					
31	Property		419,217	883,099	907,740	
32	Business Tax			100	100	
33	Subtotal Nevada		419,217	883,199	907,840	
34						
35	State of Wyoming					
36	Corporate License			3,075	3,075	
37	Property	478,308		1,027,339	991,977	
38	Subtotal Wyoming	478,308		1,030,414	995,052	
39	Other States Income	-1,351		54,853	21,768	
40	Payroll Adjustment			-11,789,296		
41	TOTAL	2,845,258	1,427,415	10,340,056	67,449,193	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/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
-44,279,599		10,945,612			-16,103,999	2
409		11,476,651				3
-36		124,895				4
-44,279,226		22,547,158			-16,103,999	5
						6
						7
4,978,404	-75	10,969,659				8
14,996					29,992	9
-3,798,000		-4,350,732			560,358	10
95,195		1,559,972				11
6,204		175,196				12
		1,728,039				13
	150	150				14
1,296,799	75	10,082,284			590,350	15
						16
						17
	1,044,661	2,052,307				18
	754				1,473	19
-212,449		89,700			28,845	20
		119,843				21
-14		12,554				22
137,706		541,650				23
-74,757	1,045,415	2,816,054			30,318	24
						25
						26
99,130		198,721				27
99,130		198,721				28
						29
						30
	443,859	883,099				31
		100				32
	443,859	883,199				33
						34
						35
		3,075				36
513,670		1,027,339				37
513,670		1,030,414				38
31,734		42,742			12,111	39
		-11,789,296				40
-42,412,650	1,489,349	25,811,276			-15,471,220	41

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Schedule Page: 262 Line No.: 1 Column: i

This footnote is for the total of Column I on page 263. The total of column I and the amounts associated with accounts 408.1 & 409.1 in column I should total back to the sum of Lines 14,15 & 16 on page 114. For the year 2008 this cross-check will not work as the total of lines 14-16 on page 114 is $13,474,751 lower than line 41 page 263. This difference represents an amount booked for the accounting of FIN #48. When FIN #48 was booked it does use account 409.1, however the other side is not associated with accounts 236 or 165. The offset resides in FERC accounts 190xxx and various other accounts. Therefore the amount for Fin #48 show up on page 114 but will not be on pages 262& 263.

Schedule Page: 262 Line No.: 2 Column: I

Account	409.2	$ 3,078,591
	134.1	(19,107,159)
	234	(75,431)
Total		$(16,103,999)

Schedule Page: 262 Line No.: 9 Column: I

Account 408.2 $ 29,992

Schedule Page: 262 Line No.: 10 Column: I

Account	409.2	$ 573,928
	234	(13,570)
Total		$ 560,358

Schedule Page: 262 Line No.: 19 Column: I

Account 408.2 $1,473

Schedule Page: 262 Line No.: 20 Column: I

Account	409.2	$ 29,535
	234	(690)
Total		$ 28,845

Schedule Page: 262 Line No.: 39 Column: I

Account	409.2	$ 12,341
	234	(230)
Total		$ 12,111

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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 Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%	1,080,786				139,291	
4	7%						
5	10%	30,474,981				1,751,095	
6	11%	1,347,508				27,085	
7	Other- State	38,097,435	411.4	5,759,370	411.4	1,572,532	
8	TOTAL	71,000,710		5,759,370		3,490,003	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Line 6 Col A 11%						
11							
12	State of Idaho	38,097,435	411.4	5,759,370	411.4	1,572,532	
13							
14							
15							
16							
17							
18							
19							
20							
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48							

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
941,495	7.76		3
			4
28,723,886	17.4		5
1,320,423	49.75		6
42,284,273	24.23		7
73,270,077			8
			9
			10
			11
42,284,273			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
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			48

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/Q4

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $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	Bureau of Land Mngt Rents/ROW	5,175,984	107, 232	1,557,401	7,057,048	10,675,631
2						
3	Point to Point Transmission Study	4,262,458	186, 242	7,067,645	5,241,440	2,436,253
4						
5	FTV	5,666,027	454	400,000	639	5,266,666
6						
7	Linden Feeder	420,523	242	420,523		
8						
9	SWIP Deposit	1,500,000	186, 4211	6,500,000	5,940,000	940,000
10						
11	Fin 48	-9,169,981	various	220,586	9,390,567	
12						
13	Fin 48 Interest	-802,050	various	282,084	1,084,134	
14						
15	Sho Ban Trans ROW	307,500	242	15,000		292,500
16						
17	Delivery Accruals	258,432	107, 401	1,037,977	978,509	198,964
18						
19	Customer Level Pay	1,826,635	142	1,444,094	671,963	1,054,504
20						
21	US Airforce Photovoltaic Generator	288,738	415	298,556	41,750	31,932
22						
23	Milner Falling Water	4,069,776	186	3,226,139	1,542,780	2,386,417
24						
25	Postretirement Benefits	3,030,160	401	358,576		2,671,584
26						
27	PURPA Cogen Deposit				8,000	8,000
28						
29	Directors Deferred Compensation	4,004,241	232	637,440	609,883	3,976,684
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	20,838,443		23,466,021	32,566,713	29,939,135

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR: Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR: Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	227,092,879	26,585,367	7,254,569
3	Gas			
4	Other			
5	TOTAL (Enter Total of lines 2 thru 4)	227,092,879	26,585,367	7,254,569
6	Non-Operating Property	244,578		
7	Other - FASB 109	308,290,095		
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	535,627,552	26,585,367	7,254,569
10	Classification of TOTAL			
11	Federal Income Tax	453,140,171	26,429,765	7,233,367
12	State Income Tax	82,487,381	155,602	21,202

NOTES

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/Q4

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

3. 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
						246,423,677	2
							3
							4
						246,423,677	5
-127,555	117,023						6
		182	6,676,392	182	32,268,657	333,882,360	7
							8
-127,555	117,023		6,676,392		32,268,657	580,306,037	9
[redacted]							10
-107,000	98,165		6,661,848		25,079,631	490,549,187	11
-20,555	18,858		14,544		7,189,026	89,756,850	12

NOTES (Continued)

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Schedule Page: 274 Line No.: 2 Column: b

Page 274 & 275 -- Accumulated Deferred Income Taxes - Other Property (Account 282)

Line No.	Account (a)	2008 Beginning Balance b	Changes during Year DR to 410.1 c	CR to 411.1 d	DR to 410.2 e	CR to 411.2 f	Adjustments Debits Acct. CR. g	Amt h	Adjustments Credits Acct. dr. i	Amount j	2008 Ending Balance k
Line 2:	Accelerated Depreciation	215,117,208	30,779,455	7,174,557							238,722,106
	Intangible Asset-Labor Deduction	12,252,496	637,828								12,890,324
	FERC Jurisdictional	7,818,502	(7,818,502)								0
	N. Valmy	657,266		76,500							580,766
	Bridger	120,057		102,400							17,657
	Engineering Fees in Acct 107	(42,828)	30,201	273,414							(286,041)
	Misc Software Develop Costs	877,669	(383,042)								494,627
	Taxable CIAC in CWIP Bal.	(9,707,491)	3,339,427	(372,302)							(5,995,762)
	TOTAL Line 2	227,092,879	26,585,367	7,254,569	-	0.00		0.00		0.00	246,423,677

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Other Electric -- See Note	47,920,162	47,678,300	32,880,218
4				
5				
6				
7				
8	Other -- See Note	7,309,438		
9	TOTAL Electric (Total of lines 3 thru 8)	55,229,600	47,678,300	32,880,218
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other -- See Note	455,886		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	55,685,486	47,678,300	32,880,218
20	Classification of TOTAL			
21	Federal Income Tax	46,712,004	39,995,137	27,581,705
22	State Income Tax	8,973,482	7,683,164	5,298,513
23	Local Income Tax			

NOTES

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

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

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
[redacted]							1
							2
						62,718,244	3
							4
							5
							6
							7
			364,179		62,388,995	69,334,254	8
			364,179		62,388,995	132,052,498	9
[redacted]							10
							11
							12
							13
							14
							15
							16
							17
-120,841	485,389					-150,344	18
-120,841	485,389		364,179		62,388,995	131,902,154	19
[redacted]							20
-101,368	407,172		305,501		52,335,264	110,646,659	21
-19,473	78,219		58,678		10,053,732	21,255,495	22
							23

NOTES (Continued)

Name of Respondent Idaho Power Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report 2008/Q4

FOOTNOTE DATA

Schedule Page: 276 Line No.: 3 Column: a

Page 276 & 277 -- Accumulated Deferred Income Taxes - Other (Account 283)

Line No.	Account (a)	2008 Beginning Balance b	Changes during Year: DR to 410.1 c	CR to 411.1 d	DR to 410.2 e	CR to 411.2 f	Adjustments Debits: Acct. cr g	Amount h	Adjustments Credits: Acct. dr i	Amount j	2008 Ending Balance k
Line 3:	PCA Expense Deferral	42,667,139	44,993,134	31,606,268							56,054,005
	Conservation Programs	3,169,251	0	1,267,696							1,901,555
	Oregon Excess Power Costs	2,340,811	501,408	1,301,446							1,540,773
	Oregon PCAM	0	2,110,996								2,110,996
	IPUC Grid West Loans	291,548	0	72,887							218,661
	Incremental Security Costs	26,895	0	26,895							
	FERC Grid West Expense	118,113	40,228	16,380							141,961
	OPUC Grid West Loans	23,616	1,794	0							25,410
	Intervenor Funding Orders	20,566	26,707	17,050							30,223
	Fixed Cost Adjustment	(838,745)	0	(1,470,693)							631,948
	PS & I Costs - Coal & CHP Plants-Write Off	100,968	4,033	42,289							62,712
	TOTAL Line 3	47,920,162	47,678,300	32,880,218	-	-		-		-	62,718,244

Schedule Page: 276 Line No.: 8 Column: a

Line 8:	FAS 158 - Pension	3,815,138					190	0	190	58,128,607	61,943,745
	FAS 158 - Postretirement Plan	3,130,106					186/190	0	186/190	4,260,388	7,390,494
	Unrealized gains on Mkt Securities	364,194					219	364,179	219	-	15
	TOTAL Line 8	7,309,438	-	-	-	-		364,179		62,388,995	69,334,254

Schedule Page: 276 Line No.: 18 Column: a

Line 18:	Advance Coal Royalties	247,769			31,064	39,095					239,738
	IRS Interest Income	151,918			(151,918)	0					0
	Oregon Non-Op Prop Tax Adj	282			13	0					295
	Unrealized Gain/Loss From Rabbit Trust	55,917			0	446,295					(390,377)
	TOTAL Line 18	455,886	-	-	(120,841)	485,390		-		-	(150,344)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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	Market to Market Short Term	553,042	175	7,941,395	8,040,433	652,080
2						
3	Demand Side Management Rider 29026	1,483,074	various	24,033,666	22,550,592	
4						
5	Demand Side Management Rider OR	410,225	various	668,305	454,907	196,827
6						
7	FAS 133 - Market to Market	33,160	175	4,072,587	4,039,427	
8						
9	Fixed Cost Adjustment - 30267	2,145,403	254, 4074	7,050,779	4,905,376	
10						
11	Fixed Cost Adjustment- Prior Yr Def		254, 4074	1,295,779	2,400,558	1,104,779
12						
13	BPA Credit-Residential - Idaho	14,956	254, 440	2,265	1,364	14,055
14						
15	BPA Credit-Residential - Oregon	(178,685)	143	536,273	714,958	
16						
17	BPA Credit-Farm - Idaho	985,918	442	991,395	5,477	
18						
19	BPA Credit-Farm - Oregon	28,538	442	28,695	157	
20						
21	Emission Sales IEEP- Order #30529				500,000	500,000
22						
23	Unfunded Accumulated Deferred Income Tax	42,967,558			1,373,355	44,340,913
24						
25	ID WAQC Carryover- Order # 29505				1,977	1,977
26						
27	Asset Retirement Oblication - Removal Cost	155,313,605	108	42,269	1,566,140	156,837,476
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	203,756,794		46,663,408	46,554,721	203,648,107

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/Q4

ELECTRIC OPERATING REVENUES (Account 400)

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

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	353,261,718	308,207,698
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	305,854,293	256,206,389
5	Large (or Ind.) (See Instr. 4)	122,302,388	101,409,337
6	(444) Public Street and Highway Lighting	2,892,343	2,479,808
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	784,310,742	668,303,232
11	(447) Sales for Resale	121,428,825	154,948,157
12	TOTAL Sales of Electricity	905,739,567	823,251,389
13	(Less) (449.1) Provision for Rate Refunds	9,979,836	1,075,534
14	TOTAL Revenues Net of Prov. for Refunds	895,759,731	822,175,855
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	3,669,976	4,050,513
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	18,889,639	19,035,198
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	19,432,928	13,910,578
22	(456.1) Revenues from Transmission of Electricity of Others	18,323,290	16,229,091
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	60,315,833	53,225,380
27	TOTAL Electric Operating Revenues	956,075,564	875,401,235

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/Q4

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
5,297,257	5,227,166	402,520	397,286	2
				3
5,860,422	5,831,537	80,636	78,670	4
3,355,202	3,453,633	122	126	5
30,833	29,489	1,257	1,012	6
				7
				8
				9
14,543,714	14,541,825	484,535	477,094	10
2,047,603	2,743,647			11
16,591,317	17,285,472	484,535	477,094	12
				13
16,591,317	17,285,472	484,535	477,094	14

Line 12, column (b) includes $ 6,080,350 of unbilled revenues.

Line 12, column (d) includes -4,999 MWH relating to unbilled revenues

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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	440 - Residential Sales:					
2	01 - Residential	5,277,646	348,722,617	402,382	13,116	0.0661
3	04 - Residential - EW	900	57,850	56	16,071	0.0643
4	05 - Residential - TOD	1,289	83,747	82	15,720	0.0650
5	15 - Dusk to dawn lighting	2,502	476,724			0.1905
6	Unbilled Revenues	14,920	3,920,780			0.2628
7	Total 440	5,297,257	353,261,718	402,520	13,160	0.0667
8						
9	442-Commercial & Industrial Sales					
10	07 - General service	188,765	15,426,300	32,264	5,851	0.0817
11	09 - General service	422,850	18,115,721	159	2,659,434	0.0428
12	09 - General service	3,315,897	163,806,595	28,635	115,799	0.0494
13	09 - General service	2,788	117,478	2	1,394,000	0.0421
14	15 - Dusk to Dawn Light	3,825	648,274			0.1695
15	19 - Uniform rate contracts	2,148,969	80,861,009	113	19,017,425	0.0376
16	19 - Uniform rate contracts	7,844	330,453	1	7,844,000	0.0421
17	19 - Uniform rate contracts	151,643	5,133,221	5	30,328,600	0.0339
18	24 - Irrigation Pumping	1,921,607	105,689,562	18,401	104,429	0.0550
19	40 - General service	14,051	871,726	1,178	11,928	0.0620
20	Commercial & Industrial & Unbill	1,037,385	37,156,342			0.0358
21	Total 442	9,215,624	428,156,681	80,758	114,114	0.0465
22						
23	444 - Public Street Lighting:					
24	40 - General service	2,633	163,839	742	3,549	0.0622
25	41 - Street lighting	24,224	2,561,549	237	102,211	0.1057
26	42 - Traffic control lighting	3,976	166,955	278	14,302	0.0420
27	Total 444	30,833	2,892,343	1,257	24,529	0.0938
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
41	TOTAL Billed	14,548,713	778,230,392	484,535	30,026	0.0535
42	Total Unbilled Rev.(See Instr. 6)	-4,999	6,080,350	0	0	-1.2163
43	TOTAL	14,543,714	784,310,742	484,535	30,016	0.0539

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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)
40						
41	TOTAL Billed	14,548,713	778,230,392	484,535	30,026	0.0535
42	Total Unbilled Rev.(See Instr. 6)	-4,999	6,080,350	0	0	-1.2163
43	TOTAL	14,543,714	784,310,742	484,535	30,016	0.0539

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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	Raft River Rural Electric	RQ	V6-44	9.433	9.433	8.145
2	Raft River Rural Electric	RQ	V6-44	n/a	n/a	n/a
3						
4	Arizona Public Service Co.	SF	WSPP	n/a	n/a	n/a
5	Avista Corp. - WWP Div.	SF	WSPP	n/a	n/a	n/a
6	Barclays Bank PLC	SF	WSPP	n/a	n/a	n/a
7	Bear Energy LP	SF	WSPP	n/a	n/a	n/a
8	Black Hills Power Inc.	OS	WSPP	n/a	n/a	n/a
9	Black Hills Power Inc.	OS	WSPP	n/a	n/a	n/a
10	Black Hills Power Inc.	SF	WSPP	n/a	n/a	n/a
11	Bonneville Power Administration	OS	WSPP	n/a	n/a	n/a
12	Bonneville Power Administration	SF	T-7	n/a	n/a	n/a
13	Bonneville Power Administration	SF	WSPP	n/a	n/a	n/a
14	BP Energy Company	SF	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/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.
57,311	656,585	1,459,683	6,000	2,122,268	1
			362,963	362,963	2
					3
72,803		1,921,438		1,921,438	4
14,524		834,078		834,078	5
67,600		3,268,590		3,268,590	6
50,350		2,938,077		2,938,077	7
			5,852	5,852	8
30,805		1,586,200		1,586,200	9
7,940		531,847		531,847	10
5,440		165,920		165,920	11
33		790		790	12
69,259		4,139,910		4,139,910	13
207,917		13,726,957		13,726,957	14
57,311	656,585	1,459,683	368,963	2,485,231	
1,990,923	0	111,561,977	7,381,617	118,943,594	
2,048,234	**656,585**	**113,021,660**	**7,750,580**	**121,428,825**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/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)	Average Monthly CP Demand (f)
1	British Columbia Transmission Corp.	SF	T-7	n/a	n/a	n/a
2	Cargill Power Markets LLC	OS	WSPP	n/a	n/a	n/a
3	Cargill Power Markets LLC	SF	WSPP	n/a	n/a	n/a
4	Chelan Co PUD	SF	WSPP	n/a	n/a	n/a
5	Citigroup Energy Inc.	SF	WSPP	n/a	n/a	n/a
6	Clatskanie PUD	SF	WSPP	n/a	n/a	n/a
7	Conoco Phillips Company	SF	WSPP	n/a	n/a	n/a
8	Constellation Energy Commodities Group,	OS	WSPP	n/a	n/a	n/a
9	Constellation Energy Commodities Group,	OS	WSPP	n/a	n/a	n/a
10	Constellation Energy Commodities Group,	SF	WSPP	n/a	n/a	n/a
11	Coral Power, LLC	OS	WSPP	n/a	n/a	n/a
12	Coral Power, LLC	OS	WSPP	n/a	n/a	n/a
13	Coral Power, LLC	OS	WSPP	n/a	n/a	n/a
14	Coral Power, LLC	SF	WSPP	n/a	n/a	n/a
	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
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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		57		57	1
			1,729,270	1,729,270	2
118,346		6,490,596		6,490,596	3
423		25,600		25,600	4
46,867		3,161,396		3,161,396	5
1,400		80,200		80,200	6
400		31,900		31,900	7
7,645		265,465		265,465	8
			223,301	223,301	9
136,292		8,079,780		8,079,780	10
10,206		740,716		740,716	11
			87,345	87,345	12
27,109		1,818,139		1,818,139	13
4,092		208,535		208,535	14
57,311	656,585	1,459,683	368,963	2,485,231	
1,990,923	0	111,561,977	7,381,617	118,943,594	
2,048,234	**656,585**	**113,021,660**	**7,750,580**	**121,428,825**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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	DB Energy Trading, LLC	SF	WSPP	n/a	n/a	n/a
2	El Paso Electric Company	SF	WSPP	n/a	n/a	n/a
3	Energy Authority, The	SF	WSPP	n/a	n/a	n/a
4	Eugene Water & Electric Board	SF	WSPP	n/a	n/a	n/a
5	Fortis Energy Marketing & Trading GP	SF	WSPP	n/a	n/a	n/a
6	Grant County P.U.D.	SF	WSPP	n/a	n/a	n/a
7	Highland Energy LLC	OS	WSPP	n/a	n/a	n/a
8	Highland Energy LLC	SF	WSPP	n/a	n/a	n/a
9	United Materials of Great Falls	LF	V6-61	n/a	n/a	n/a
10	IBERDROLA RENEWABLES, Inc.	OS	WSPP	n/a	n/a	n/a
11	IBERDROLA RENEWABLES, Inc.	SF	WSPP	n/a	n/a	n/a
12	Integrys Energy Services, Inc.	OS	WSPP	n/a	n/a	n/a
13	Integrys Energy Services, Inc.	SF	WSPP	n/a	n/a	n/a
14	J. Aron & Company	SF	WSPP	n/a	n/a	n/a
	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
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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.
1,400		67,000		67,000	1
178		4,323		4,323	2
684		18,234		18,234	3
5,442		325,686		325,686	4
32,852		1,898,047		1,898,047	5
6,845		402,650		402,650	6
			235	235	7
5,085		282,360		282,360	8
			26,446	26,446	9
			1,720	1,720	10
74,683		4,456,726		4,456,726	11
			486	486	12
84,378		4,679,152		4,679,152	13
2,800		190,550		190,550	14
57,311	656,585	1,459,683	368,963	2,485,231	
1,990,923	0	111,561,977	7,381,617	118,943,594	
2,048,234	**656,585**	**113,021,660**	**7,750,580**	**121,428,825**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/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	J.P. Morgan Ventures Energy Corporation	SF	WSPP	n/a	n/a	n/a
2	Lehman Brothers Commodity Services, Inc	SF	WSPP	n/a	n/a	n/a
3	Morgan Stanley Capital Group Inc.	OS	WSPP	n/a	n/a	n/a
4	Morgan Stanley Capital Group Inc.	SF	WSPP	n/a	n/a	n/a
5	NorthWestern Energy	OS	WSPP	n/a	n/a	n/a
6	Pacific Northwest Generating Cooperativ	SF	WSPP	n/a	n/a	n/a
7	PacifiCorp Inc.	OS	WSPP	n/a	n/a	n/a
8	PacifiCorp Inc.	SF	T-7	n/a	n/a	n/a
9	PacifiCorp Inc.	SF	WSPP	n/a	n/a	n/a
10	Portland General Electric Company	OS	WSPP	n/a	n/a	n/a
11	Portland General Electric Company	OS	WSPP	n/a	n/a	n/a
12	Portland General Electric Company	SF	WSPP	n/a	n/a	n/a
13	Powerex Corp.	OS	WSPP	n/a	n/a	n/a
14	Powerex Corp.	OS	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/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.
8,200		414,100		414,100	1
5,334		114,338		114,338	2
			92,133	92,133	3
45,816		2,801,280		2,801,280	4
			423	423	5
400		32,900		32,900	6
			1,971,398	1,971,398	7
294		19,014		19,014	8
34,632		1,995,643		1,995,643	9
			38,383	38,383	10
1,900		106,400		106,400	11
13,001		681,935		681,935	12
			1,734,317	1,734,317	13
91,849		5,679,851		5,679,851	14
57,311	656,585	1,459,683	368,963	2,485,231	
1,990,923	0	111,561,977	7,381,617	118,943,594	
2,048,234	**656,585**	**113,021,660**	**7,750,580**	**121,428,825**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/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	Powerex Corp.	SF	WSPP	n/a	n/a	n/a
2	PPL EnergyPlus, LLC	OS	WSPP	n/a	n/a	n/a
3	PPL EnergyPlus, LLC	OS	WSPP	n/a	n/a	n/a
4	PPL EnergyPlus, LLC	SF	WSPP	n/a	n/a	n/a
5	PPM Energy, Inc.	OS	WSPP	n/a	n/a	n/a
6	PPM Energy, Inc.	SF	WSPP	n/a	n/a	n/a
7	Prudential Bache Commodities, LLC	OS	-	n/a	n/a	n/a
8	Public Service Co. of Colorado	OS	WSPP	n/a	n/a	n/a
9	Public Service Co. of Colorado	SF	WSPP	n/a	n/a	n/a
10	Puget Sound Energy, Inc.	SF	WSPP	n/a	n/a	n/a
11	Rainbow Energy Marketing Corporation	OS	WSPP	n/a	n/a	n/a
12	Rainbow Energy Marketing Corporation	OS	WSPP	n/a	n/a	n/a
13	Rainbow Energy Marketing Corporation	SF	WSPP	n/a	n/a	n/a
14	Sacramento Municipal Utility District	SF	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/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.
239,380		12,791,331		12,791,331	1
			70,472	70,472	2
176		1,760		1,760	3
16,395		640,820		640,820	4
			9,822	9,822	5
52,200		2,992,200		2,992,200	6
			-345,380	-345,380	7
640		24,320		24,320	8
4,000		214,636		214,636	9
55,219		2,932,891		2,932,891	10
			422,601	422,601	11
6,066		211,246		211,246	12
11,409		456,343		456,343	13
400		18,000		18,000	14
57,311	656,585	1,459,683	368,963	2,485,231	
1,990,923	0	111,561,977	7,381,617	118,943,594	
2,048,234	**656,585**	**113,021,660**	**7,750,580**	**121,428,825**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Seattle City Light	SF	WSPP	n/a	n/a	n/a
2	Sempra Energy Solutions	SF	WSPP	n/a	n/a	n/a
3	Sempra Energy Trading Corporation	OS	WSPP	n/a	n/a	n/a
4	Sempra Energy Trading Corporation	SF	WSPP	n/a	n/a	n/a
5	Sempra Energy Trading LLC	SF	WSPP	n/a	n/a	n/a
6	Shell Energy North America (US), L.P.	OS	WSPP	n/a	n/a	n/a
7	Shell Energy North America (US), L.P.	OS	WSPP	n/a	n/a	n/a
8	Shell Energy North America (US), L.P.	SF	WSPP	n/a	n/a	n/a
9	Sierra Pacific Power Company	OS	WSPP	n/a	n/a	n/a
10	Sierra Pacific Power Company	OS	WSPP	n/a	n/a	n/a
11	Sierra Pacific Power Company	SF	T-7	n/a	n/a	n/a
12	Sierra Pacific Power Company	SF	WSPP	n/a	n/a	n/a
13	Silicon Valley Power	SF	WSPP	n/a	n/a	n/a
14	Snohomish County PUD	SF	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/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			Total ($) (h+i+j) (k)	Line No.
	Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)		
17,685		1,143,800		1,143,800	1
400		23,176		23,176	2
			44,350	44,350	3
10,400		748,800		748,800	4
184,438		10,482,086		10,482,086	5
11,110		348,167		348,167	6
			122,210	122,210	7
26,160		1,084,912		1,084,912	8
			1,319,220	1,319,220	9
138		8,280		8,280	10
151		8,489		8,489	11
2,917		181,197		181,197	12
800		68,000		68,000	13
4,847		220,635		220,635	14
57,311	656,585	1,459,683	368,963	2,485,231	
1,990,923	0	111,561,977	7,381,617	118,943,594	
2,048,234	**656,585**	**113,021,660**	**7,750,580**	**121,428,825**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/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	SUEZ Energy Marketing NA, Inc.	SF	WSPP	n/a	n/a	n/a
2	TransAlta Energy Marketing (U.S.) Inc.	OS	WSPP	n/a	n/a	n/a
3	TransAlta Energy Marketing (U.S.) Inc.	SF	WSPP	n/a	n/a	n/a
4	UBS Securities LLC	OS	-	n/a	n/a	n/a
5						
6						
7						
8						
9						
10						
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.
2,000		146,300		146,300	1
			422	422	2
48,767		2,628,208		2,628,208	3
			-173,409	-173,409	4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
57,311	656,585	1,459,683	368,963	2,485,231	
1,990,923	0	111,561,977	7,381,617	118,943,594	
2,048,234	**656,585**	**113,021,660**	**7,750,580**	**121,428,825**	

Schedule Page: 310 Line No.: 1 Column: j

Schedule Page: 310 Line No.: 2 Column: j
Network Transmission Charges

Schedule Page: 310 Line No.: 8 Column: j
Financial Transmission Losses

Schedule Page: 310 Line No.: 9 Column: i
Non-firm Sales

Schedule Page: 310 Line No.: 11 Column: i
Unit Contingent

Schedule Page: 310.1 Line No.: 2 Column: j
Financial Transmission Losses

Schedule Page: 310.1 Line No.: 8 Column: i
Unit Contingent

Schedule Page: 310.1 Line No.: 9 Column: j
Financial Transmission Losses

Schedule Page: 310.1 Line No.: 11 Column: i
Unit Contingent

Schedule Page: 310.1 Line No.: 12 Column: j
Financial Transmission Losses

Schedule Page: 310.1 Line No.: 13 Column: i
Non-firm Sales

Schedule Page: 310.2 Line No.: 7 Column: j
Financial Transmission Losses

Schedule Page: 310.2 Line No.: 9 Column: a
Contract expires 5/31/2013

Schedule Page: 310.2 Line No.: 9 Column: j
Spinning or Operating Reserves

Schedule Page: 310.2 Line No.: 10 Column: j
Financial Transmission Losses

Schedule Page: 310.2 Line No.: 12 Column: j
Financial Transmission Losses

Schedule Page: 310.3 Line No.: 3 Column: j
Financial Transmission Losses

Schedule Page: 310.3 Line No.: 5 Column: j
Financial Transmission Losses

Schedule Page: 310.3 Line No.: 7 Column: j
Financial Transmission Losses

Schedule Page: 310.3 Line No.: 10 Column: j
Financial Transmission Losses

Schedule Page: 310.3 Line No.: 11 Column: i
Non-firm Sales

Schedule Page: 310.3 Line No.: 13 Column: j
Financial Transmission Losses

Schedule Page: 310.3 Line No.: 14 Column: i
Non-firm Sales

Schedule Page: 310.4 Line No.: 2 Column: j
Financial Transmission Losses

Schedule Page: 310.4 Line No.: 3 Column: i
Non-firm Sales

Schedule Page: 310.4 Line No.: 5 Column: j
Financial Transmission Losses

Schedule Page: 310.4 Line No.: 7 Column: j

Prudential Bache Commodities, LLC Futures Account Document, dated September 4, 2008

Schedule Page: 310.4 Line No.: 9 Column: i

Non-firm Sales

Schedule Page: 310.4 Line No.: 11 Column: j

Financial Transmission Losses

Schedule Page: 310.4 Line No.: 12 Column: i

Non-firm Sales

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

Financial Transmission Losses

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

Unit Contingent

Schedule Page: 310.5 Line No.: 7 Column: j

Financial Transmission Losses

Schedule Page: 310.5 Line No.: 9 Column: j

Financial Transmission Losses

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

Non-firm Sales

Schedule Page: 310.6 Line No.: 2 Column: j

Financial Transmission Losses

Schedule Page: 310.6 Line No.: 4 Column: j

Institutional Futures Client Account Agreement with UBS, dated March 8, 2006

Schedule Page: 310.6 Line No.: 5 Column: g

In reference to the total MegaWatt Hours sold, page 311 does not match page 301 line 11, column d by 631 MegaWatt hours due to an adjustment that was made to statistics in our books for total sales for resale.

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/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	1,650,283	1,664,872
5	(501) Fuel	132,015,165	114,837,238
6	(502) Steam Expenses	7,376,689	6,840,109
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,817,960	2,109,889
10	(506) Miscellaneous Steam Power Expenses	7,737,497	8,068,234
11	(507) Rents	469,699	295,774
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	151,067,293	133,816,116
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	2,567,722	2,580,248
16	(511) Maintenance of Structures	398,714	649,264
17	(512) Maintenance of Boiler Plant	14,205,043	14,630,060
18	(513) Maintenance of Electric Plant	4,301,150	5,685,377
19	(514) Maintenance of Miscellaneous Steam Plant	4,322,931	5,934,851
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	25,795,560	29,479,800
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	176,862,853	163,295,916
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	5,602,490	5,235,531
45	(536) Water for Power	7,355,741	5,057,110
46	(537) Hydraulic Expenses	9,978,475	9,469,966
47	(538) Electric Expenses	1,312,586	1,391,453
48	(539) Miscellaneous Hydraulic Power Generation Expenses	3,091,676	2,825,559
49	(540) Rents	431,893	419,652
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	27,772,861	24,399,271
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	1,885,154	1,875,540
54	(542) Maintenance of Structures	1,362,031	1,281,835
55	(543) Maintenance of Reservoirs, Dams, and Waterways	808,311	541,034
56	(544) Maintenance of Electric Plant	2,495,503	2,090,274
57	(545) Maintenance of Miscellaneous Hydraulic Plant	3,135,803	2,763,207
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	9,686,802	8,551,890
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	37,459,663	32,951,161

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/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	372,614	341,622
63	(547) Fuel	17,387,509	19,484,750
64	(548) Generation Expenses	404,456	381,996
65	(549) Miscellaneous Other Power Generation Expenses	530,176	464,825
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	18,694,755	20,673,193
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	213	
70	(552) Maintenance of Structures	162,376	220,421
71	(553) Maintenance of Generating and Electric Plant	198,271	42,703
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	509,219	645,761
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	870,079	908,885
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	19,564,834	21,582,078
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	231,137,298	289,484,213
77	(556) System Control and Load Dispatching	77,979	77,489
78	(557) Other Expenses	-44,906,304	-118,678,522
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	186,308,973	170,883,180
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	420,196,323	388,712,335
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,404,396	2,334,833
84	(561) Load Dispatching	87,197	51,610
85	(561.1) Load Dispatch-Reliability	1,517	
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,635,606	2,042,253
87	(561.3) Load Dispatch-Transmission Service and Scheduling	1,069,383	1,098,119
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	90,292	66,918
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	1,805,491	1,748,408
94	(563) Overhead Lines Expenses	735,577	924,264
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	7,250,299	10,469,725
97	(566) Miscellaneous Transmission Expenses	465,343	622,227
98	(567) Rents	1,085,343	1,163,462
99	TOTAL Operation (Enter Total of lines 83 thru 98)	16,630,444	20,521,819
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	431,690	442,117
102	(569) Maintenance of Structures		111
103	(569.1) Maintenance of Computer Hardware	98,395	123,219
104	(569.2) Maintenance of Computer Software	328,872	307,535
105	(569.3) Maintenance of Communication Equipment	24,333	21,369
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	2,706,580	2,899,130
108	(571) Maintenance of Overhead Lines	3,367,619	2,341,428
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	272	2,527
111	TOTAL Maintenance (Total of lines 101 thru 110)	6,957,761	6,137,436
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	23,588,205	26,659,255

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	3,321,954	3,350,727
135	(581) Load Dispatching	3,110,301	3,049,911
136	(582) Station Expenses	1,143,619	1,120,906
137	(583) Overhead Line Expenses	3,346,471	3,432,084
138	(584) Underground Line Expenses	2,034,228	2,120,824
139	(585) Street Lighting and Signal System Expenses	130,886	148,817
140	(586) Meter Expenses	4,636,934	4,526,254
141	(587) Customer Installations Expenses	1,398,175	1,371,291
142	(588) Miscellaneous Expenses	5,464,167	5,533,555
143	(589) Rents	456,147	644,840
144	TOTAL Operation (Enter Total of lines 134 thru 143)	25,042,882	25,299,209
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	319,660	262,635
147	(591) Maintenance of Structures	2,323	
148	(592) Maintenance of Station Equipment	3,534,603	3,493,145
149	(593) Maintenance of Overhead Lines	13,759,196	12,504,013
150	(594) Maintenance of Underground Lines	1,235,321	1,351,055
151	(595) Maintenance of Line Transformers	445,190	169,689
152	(596) Maintenance of Street Lighting and Signal Systems	665,088	476,928
153	(597) Maintenance of Meters	862,861	927,906
154	(598) Maintenance of Miscellaneous Distribution Plant	354,999	127,981
155	TOTAL Maintenance (Total of lines 146 thru 154)	21,179,241	19,313,352
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	46,222,123	44,612,561
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	341,842	454,931
160	(902) Meter Reading Expenses	5,752,965	5,422,623
161	(903) Customer Records and Collection Expenses	11,773,961	8,177,910
162	(904) Uncollectible Accounts	3,681,954	2,009,863
163	(905) Miscellaneous Customer Accounts Expenses	468	336
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	21,551,190	16,065,663

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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	299,410	301,871
168	(908) Customer Assistance Expenses	27,674,740	21,911,476
169	(909) Informational and Instructional Expenses		
170	(910) Miscellaneous Customer Service and Informational Expenses	860,302	884,228
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	28,834,452	23,097,575
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses		
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)		
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	57,537,274	49,783,914
182	(921) Office Supplies and Expenses	14,791,345	17,790,599
183	(Less) (922) Administrative Expenses Transferred-Credit	22,736,029	27,708,517
184	(923) Outside Services Employed	13,597,223	11,232,903
185	(924) Property Insurance	3,103,669	3,159,426
186	(925) Injuries and Damages	7,548,140	5,448,359
187	(926) Employee Pensions and Benefits	22,840,421	27,872,099
188	(927) Franchise Requirements	1,549	1,200
189	(928) Regulatory Commission Expenses	4,832,197	6,030,254
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	236,828	519,845
192	(930.2) Miscellaneous General Expenses	3,515,410	3,497,158
193	(931) Rents	6,827	11,570
194	TOTAL Operation (Enter Total of lines 181 thru 193)	105,274,854	97,638,810
195	Maintenance		
196	(935) Maintenance of General Plant	4,149,187	3,771,715
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	109,424,041	101,410,525
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	649,816,334	600,557,914

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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	Willis and Betty Deveny/Shinglecreek	LU	-	N/A	N/A	N/A
2	James B. Howell / CHI Elkcreek	LU	-	N/A	N/A	N/A
3	Tamarack Energy Partnership	LU	-	4.942Mw		
4	Owyhee Irrigation District					
5	Mitchell Butte	LU	-	N/A	N/A	N/A
6	Owyhee Dam	LU	-	N/A	N/A	N/A
7	Tunnel #1	LU	-	N/A	N/A	N/A
8	Reynolds Irrigation District	LU	-	N/A	N/A	N/A
9	Clifton E. Jenson/Birchcreek	LU	-	.05Mw		
10	Snake River Pottery	LU	-	N/A	N/A	N/A
11	White Water Ranch	LU	-	N/A	N/A	N/A
12	John R LeMoyne	LU	-	N/A	N/A	N/A
13	David R Snedigar	LU	-	N/A	N/A	N/A
14	Mud Creek White Hydro, Inc	LU	-	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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.
868				59,199		59,199	1
3,379				247,077		247,077	2
31,361			1,576,498	1,121,933		2,698,431	3
							4
6,542				123,714		123,714	5
20,135				215,656		215,656	6
11,123				1,110,391		1,110,391	7
1,099				80,252		80,252	8
298			17,500	7,723		25,223	9
372				24,499		24,499	10
716				47,137		47,137	11
617				34,002		34,002	12
1,345				92,351		92,351	13
485				31,690		31,690	14
3,716,429	106,826	288,567	2,815,124	225,793,335	2,528,839	231,137,298	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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	Rim View Trout Company	OS	-	N/A	N/A	N/A
2	Curry Cattle Company	LU	-	.084Mw		
3	Branchflower/Trout Company	LU	-	N/A	N/A	N/A
4	Big Wood Canal Company					
5	Black Canyon	LU	-	N/A	N/A	N/A
6	Jim Knight	LU	-	N/A	N/A	N/A
7	Sagebrush	LU	-	N/A	N/A	N/A
8	Fisheries Development	OS	-	N/A	N/A	N/A
9	Shorock Hydro Inc.					
10	Shoshone Cspp	LU	-	N/A	N/A	N/A
11	Shoshone #2	LU	-	N/A	N/A	N/A
12	Rock Creek #1 Joint Venture	LU	-	1.732Mw		
13	Richard Kaster					
14	Box Canyon	LU	-	N/A	N/A	N/A
	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.
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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.
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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.
1,299				51,195		51,195	1
559			26,796	15,258		42,054	2
831				56,279		56,279	3
							4
335				22,717		22,717	5
1,326				92,686		92,686	6
511				35,010		35,010	7
958				39,450		39,450	8
							9
1,534				119,562		119,562	10
2,184				144,965		144,965	11
6,486			552,508	173,303		725,811	12
							13
1,687				107,783		107,783	14
3,716,429	106,826	288,567	2,815,124	225,793,335	2,528,839	231,137,298	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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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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	Briggs Creek	LU	-	N/A	N/A	N/A
2	David McCollum/Canyon Springs	LU	-	N/A	N/A	N/A
3	H.K. Hydro Mud Creek S & S	LU	-	N/A	N/A	N/A
4	Allan Ravenscroft/Malad River	LU	-	.488Mw		
5	William Arkoosh/Littlewood	LU	-	N/A	N/A	N/A
6	Clear Springs Food Inc.	LU	-	N/A	N/A	N/A
7	Koyle Hydro Inc.	LU	-	N/A	N/A	N/A
8	Kasel & Witherspoon	LU	-	N/A	N/A	N/A
9	Lateral 10 Ventures	LU	-	N/A	N/A	N/A
10	Crystal Springs Hydro	LU	-	N/A	N/A	N/A
11	Pigeon Cove Power	LU	-	1.389		
12	Consolidated Hydro Inc. / Enel		-			
13	GeoBon #2	LU	-	N/A	N/A	N/A
14	Barber Dam	LU	-	N/A	N/A	N/A
	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.
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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.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
3,549				233,539		233,539	1
802				32,314		32,314	2
1,523				107,236		107,236	3
1,810			155,672	49,306		204,978	4
3,294				239,152		239,152	5
3,493				286,718		286,718	6
2,873				231,390		231,390	7
3,596				270,026		270,026	8
8,460				537,129		537,129	9
8,111				534,976		534,976	10
8,262			486,150	190,931		677,081	11
							12
2,961				219,434		219,434	13
11,131				559,519		559,519	14
3,716,429	106,826	288,567	2,815,124	225,793,335	2,528,839	231,137,298	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/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.
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LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

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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 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	Rock Creek #2	LU	-	N/A	N/A	N/A
2	Dietrich Drop	LU	-	N/A	N/A	N/A
3	Lowline #2	LU	-	N/A	N/A	N/A
4	Little Mac Power Co./Cedar Draw	LU	-	N/A	N/A	N/A
5	South Forks Joint Venture/Lowline Cana	LU	-	N/A	N/A	N/A
6	Little Wood River Irrigation District	LU	-	N/A	N/A	N/A
7	Marco Rancher's Irrigation Inc.	LU	-	N/A	N/A	N/A
8	Faulkner Brothers Hydro Inc.	LU	-	N/A	N/A	N/A
9	Magic Reservoir Hydro	LU	-	N/A	N/A	N/A
10	Bypass Limited	LU	-	N/A	N/A	N/A
11	SE Hazelton A LP	LU	-	N/A	N/A	N/A
12	Claudia Burkhardt/Sunshine Power	OS	-	N/A	N/A	N/A
13	Lemhi Hydro Power Co./Schaffner	LU	-	N/A	N/A	N/A
14	J R Simplot Co.	LU	-	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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)	
6,483				322,354		322,354	1
12,681				683,227		683,227	2
9,797				508,947		508,947	3
3,394				219,234		219,234	4
27,983				1,971,611		1,971,611	5
3,865				287,088		287,088	6
2,581				172,577		172,577	7
3,179				235,858		235,858	8
8,729				464,027		464,027	9
26,290				1,387,073		1,387,073	10
22,840				1,151,559		1,151,559	11
73				3,072		3,072	12
1,349				100,500		100,500	13
69,798				3,780,446		3,780,446	14
3,716,429	106,826	288,567	2,815,124	225,793,335	2,528,839	231,137,298	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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	Blind Canyon Hydro	LU	-	N/A	N/A	N/A
2	City of Hailey	LU	-	N/A	N/A	N/A
3	City of Pocatello	LU	-	N/A	N/A	N/A
4	Marysville Hydro Partners/Falls River	LU	-	N/A	N/A	N/A
5	Wilson Power Company	LU	-	N/A	N/A	N/A
6	Hazelton B Power Company	LU	-	N/A	N/A	N/A
7	Pristine Springs Inc. #1	LU	-	N/A	N/A	N/A
8	Vaagen Brothers Lumber Inc.	LU	-	N/A	N/A	N/A
9	Horseshoe Bend Hydro	LU	-	N/A	N/A	N/A
10	Contractors Power Group Inc./Mile 28	LU	-	N/A	N/A	N/A
11	Rupert Cogeneration Partners/Magic Val	LU	-	N/A	N/A	N/A
12	Tasco - Nampa	OS	-	N/A	N/A	N/A
13	Pristine Springs Inc # 3	LU	-	N/A	N/A	N/A
14	Ted S. Sorenson/Tiber Dam	LU	-	N/A	N/A	N/A
	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)	
3,892				320,216		320,216	1
129				8,793		8,793	2
1,246				87,381		87,381	3
49,731				3,186,605		3,186,605	4
25,863				1,769,188		1,769,188	5
22,212				1,520,161		1,520,161	6
848				46,452		46,452	7
24,334				1,620,710		1,620,710	8
40,147				2,680,900		2,680,900	9
3,454				234,480		234,480	10
64,432				3,895,813		3,895,813	11
608				24,961		24,961	12
1,371				73,520		73,520	13
27,649				1,304,455		1,304,455	14
3,716,429	106,826	288,567	2,815,124	225,793,335	2,528,839	231,137,298	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Fossil Gulch Wind	LU	-	N/A	N/A	N/A
2	G2 Energy Hidden Hollow	LU	-	N/A	N/A	N/A
3	Horseshoe Bend Wind/United Materials	LU	-	N/A	N/A	N/A
4	Horseshoe Bend Wind/United Materials	LU	-	N/A	N/A	N/A
5	Horseshoe Bend Wind/United Materials	LU	-	N/A	N/A	N/A
6	Riverside Hydro Mora Drop	LU	-	N/A	N/A	N/A
7	J.M. Miller/Sahko Hydro	LU	-	N/A	N/A	N/A
8	D.R. Johnson Lumber/Co Gen Co	SF	-	N/A	N/A	N/A
9	Twin Falls Energy/Lowline Midway Hydro	LU	-	N/A	N/A	N/A
10	US Geothermal / Raft River Geothermal#	LU	-	N/A	N/A	N/A
11	Bennett Creek Wind Farm	LU	-	N/A	N/A	N/A
12	Bettencourt DryCreek Biofactory	LU	-	N/A	N/A	N/A
13	Big Sky Dairy Digester	LU	-	N/A	N/A	N/A
14	Hot Springs Wind Farm	LU	-	N/A	N/A	N/A
	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.
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	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
28,347				1,378,525		1,378,525	1
21,476				1,038,029		1,038,029	2
19,387				919,966		919,966	3
-4							4
-6							5
4,290				233,020		233,020	6
82				2,683		2,683	7
23,193				1,973,528		1,973,528	8
9,015				572,614		572,614	9
18,141				875,209		875,209	10
5,049				243,594		243,594	11
2,306				84,516		84,516	12
312				10,252		10,252	13
3,543				120,611		120,611	14
3,716,429	106,826	288,567	2,815,124	225,793,335	2,528,839	231,137,298	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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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SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

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

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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.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Other Purchased Power					
2	Arizona Public Service Co.	SF	WSPP	N/A	N/A	N/A
3	Avista Corp. - WWP Div.	SF	T-12	N/A	N/A	N/A
4	Avista Corp. - WWP Div.	SF	T-10	N/A	N/A	N/A
5	Avista Corp. - WWP Div.	SF	WSPP	N/A	N/A	N/A
6	Avista Corp. - WWP Div.	OS	WSPP	N/A	N/A	N/A
7	Barclays Bank PLC	SF	WSPP	N/A	N/A	N/A
8	Bear Energy LP	SF	WSPP	N/A	N/A	N/A
9	Benton County PUD	SF	WSPP	N/A	N/A	N/A
10	Black Hills Power Inc.	OS	WSPP	N/A	N/A	N/A
11	Black Hills Power Inc.	SF	WSPP	N/A	N/A	N/A
12	Bonneville Power Administration	OS	WSPP	N/A	N/A	N/A
13	Bonneville Power Administration	SF	WSPP	N/A	N/A	N/A
14	BP Energy Company	SF	WSPP	N/A	N/A	N/A
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/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)	
							1
169,121				10,623,413		10,623,413	2
67				3,589		3,589	3
					100	100	4
60,217				3,214,317		3,214,317	5
					624,528	624,528	6
76,400				3,901,100		3,901,100	7
83,000				4,526,500		4,526,500	8
390				27,620		27,620	9
56,844				3,167,374		3,167,374	10
12,042				637,104		637,104	11
125				9,375		9,375	12
76,908				4,085,880		4,085,880	13
83,378				6,338,062		6,338,062	14
3,716,429	106,826	288,567	2,815,124	225,793,335	2,528,839	231,137,298	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/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	Cargill Power Markets LLC	SF	WSPP	N/A	N/A	N/A
2	Chelan Co PUD	SF	WSPP	N/A	N/A	N/A
3	Citigroup Energy Inc.	SF	WSPP	N/A	N/A	N/A
4	Clatskanie PUD	SF	WSPP	N/A	N/A	N/A
5	Constellation Energy Commodities Group	SF	WSPP	N/A	N/A	N/A
6	Coral Power, LLC	OS	WSPP	N/A	N/A	N/A
7	Coral Power, LLC	SF	WSPP	N/A	N/A	N/A
8	DB Energy Trading, LLC	SF	WSPP	N/A	N/A	N/A
9	Douglas County PUD	SF	WSPP	N/A	N/A	N/A
10	El Paso Electric Company	SF	WSPP	N/A	N/A	N/A
11	Energy Authority, The	SF	WSPP	N/A	N/A	N/A
12	Eugene Water & Electric Board	SF	WSPP	N/A	N/A	N/A
13	Fortis Energy Marketing & Trading GP	SF	WSPP	N/A	N/A	N/A
14	Franklin County P.U.D.	SF	WSPP	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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)	
118,696				7,222,625		7,222,625	1
7,618				137,200		137,200	2
169,800				13,608,670		13,608,670	3
1,600				8,000		8,000	4
124,497				8,121,588		8,121,588	5
235				9,400		9,400	6
30,551				2,155,040		2,155,040	7
13,800				467,910		467,910	8
6,602				157,169		157,169	9
600				36,200		36,200	10
7,078				247,420		247,420	11
6,800				472,200		472,200	12
169,000				11,505,600		11,505,600	13
130				9,120		9,120	14
3,716,429	106,826	288,567	2,815,124	225,793,335	2,528,839	231,137,298	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Grant County P.U.D.	SF	WSPP	N/A	N/A	N/A
2	Grays Harbor PUD	SF	WSPP	N/A	N/A	N/A
3	Highland Energy LLC	SF	WSPP	N/A	N/A	N/A
4	IBERDROLA RENEWABLES, Inc.	SF	WSPP	N/A	N/A	N/A
5	Integrys Energy Services, Inc.	OS	WSPP	N/A	N/A	N/A
6	Integrys Energy Services, Inc.	SF	WSPP	N/A	N/A	N/A
7	J. Aron & Company	SF	WSPP	N/A	N/A	N/A
8	J.P. Morgan Ventures Energy Corporatio	SF	WSPP	N/A	N/A	N/A
9	Lehman Brothers Commodity Services, In	SF	WSPP	N/A	N/A	N/A
10	Morgan Stanley Capital Group Inc.	SF	WSPP	N/A	N/A	N/A
11	Nevada Power Company	SF	WSPP	N/A	N/A	N/A
12	NorthWestern Energy	SF	T-7	N/A	N/A	N/A
13	NorthWestern Energy	SF	WSPP	N/A	N/A	N/A
14	Pacific Northwest Generating Cooperati	SF	WSPP	N/A	N/A	N/A
	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)	
2,566				103,237		103,237	1
230				15,590		15,590	2
934				19,350		19,350	3
126,602				8,315,212		8,315,212	4
350				26,950		26,950	5
93,600				7,336,256		7,336,256	6
7,600				559,100		559,100	7
200				7,810		7,810	8
12,400				629,600		629,600	9
166,856				10,063,897		10,063,897	10
125				9,600		9,600	11
86				4,735		4,735	12
3,155				165,810		165,810	13
1,400				99,000		99,000	14
3,716,429	106,826	288,567	2,815,124	225,793,335	2,528,839	231,137,298	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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 Inc.	SF	T-13	N/A	N/A	N/A
2	PacifiCorp Inc.	SF	WSPP	N/A	N/A	N/A
3	PacifiCorp Inc.	OS	WSPP	N/A	N/A	N/A
4	Portland General Electric Company	SF	T-14	N/A	N/A	N/A
5	Portland General Electric Company	OS	WSPP	N/A	N/A	N/A
6	Portland General Electric Company	SF	WSPP	N/A	N/A	N/A
7	Powerex Corp.	OS	WSPP	N/A	N/A	N/A
8	Powerex Corp.	SF	WSPP	N/A	N/A	N/A
9	PPL EnergyPlus, LLC	LF	WSPP	N/A	N/A	N/A
10	PPL EnergyPlus, LLC	OS	WSPP	N/A	N/A	N/A
11	PPL EnergyPlus, LLC	SF	WSPP	N/A	N/A	N/A
12	PPM Energy, Inc.	SF	WSPP	N/A	N/A	N/A
13	Prudential Bache Commodities, LLC	OS	-	N/A	N/A	N/A
14	Public Service Company of New Mexico	SF	WSPP	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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)	
304				13,501		13,501	1
143,341				8,466,563		8,466,563	2
					549,297	549,297	3
97				5,772		5,772	4
400				23,050		23,050	5
62,756				4,563,844		4,563,844	6
4,000				284,800		284,800	7
126,033				8,835,440		8,835,440	8
102,256				4,550,392		4,550,392	9
6,314				419,777		419,777	10
47,197				2,590,749		2,590,749	11
24,816				1,610,882		1,610,882	12
					116,272	116,272	13
580				32,230		32,230	14
3,716,429	106,826	288,567	2,815,124	225,793,335	2,528,839	231,137,298	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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	Puget Sound Energy, Inc.	SF	T-9	N/A	N/A	N/A
2	Puget Sound Energy, Inc.	SF	WSPP	N/A	N/A	N/A
3	Raft River Energy I LLC	LU	-	N/A	N/A	N/A
4	Rainbow Energy Marketing Corporation	OS	WSPP	N/A	N/A	N/A
5	Rainbow Energy Marketing Corporation	SF	WSPP	N/A	N/A	N/A
6	Seattle City Light	SF	WSPP	N/A	N/A	N/A
7	Sempra Energy Trading Corporation	SF	WSPP	N/A	N/A	N/A
8	Sempra Energy Trading LLC	SF	WSPP	N/A	N/A	N/A
9	Sempra Energy Trading LLC	OS	-	N/A	N/A	N/A
10	Shell Energy North America (US), L.P.	SF	WSPP	N/A	N/A	N/A
11	Sierra Pacific Power Company	SF	55	N/A	N/A	N/A
12	Sierra Pacific Power Company	OS	WSPP	N/A	N/A	N/A
13	Sierra Pacific Power Company	SF	WSPP	N/A	N/A	N/A
14	Sierra Pacific Power Company	OS	WSPP	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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)	
102				5,722		5,722	1
21,982				1,457,078		1,457,078	2
67,620				3,845,524		3,845,524	3
4,683				249,580		249,580	4
1,275				42,195		42,195	5
10,972				687,985		687,985	6
58,000				3,682,000		3,682,000	7
189,200				13,640,660		13,640,660	8
					190,632	190,632	9
13,356				480,501		480,501	10
53				2,642		2,642	11
2,421				58,880		58,880	12
9,434				386,145		386,145	13
					21,128	21,128	14
3,716,429	106,826	288,567	2,815,124	225,793,335	2,528,839	231,137,298	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/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	Snohomish County PUD	SF	WSPP	N/A	N/A	N/A
2	SUEZ Energy Marketing NA, Inc.	SF	WSPP	N/A	N/A	N/A
3	Tacoma Power	SF	WSPP	N/A	N/A	N/A
4	Telocaset Wind Power Partners LLC	LU	APP-A	N/A	N/A	N/A
5	TransAlta Energy Marketing (U.S.) Inc.	SF	WSPP	N/A	N/A	N/A
6	Tucson Electric Power Company	SF	WSPP	N/A	N/A	N/A
7	UBS AG, London Branch	SF	WSPP	N/A	N/A	N/A
8	UBS Securities LLC	OS	-	N/A	N/A	N/A
9	Western Area Power Administration (WAL	SF	WSPP	N/A	N/A	N/A
10	Net Metering Customers	OS	-	N/A	N/A	N/A
11	Power Exchanges					
12	Bonneville Power Administration	EX	-			
13	NorthWestern Energy	EX	-			
14	PacifiCorp Inc.	EX	-			
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
16,045				768,279		768,279	1
475				38,475		38,475	2
4,121				251,966		251,966	3
268,207				13,333,647		13,333,647	4
34,916				1,739,976		1,739,976	5
13				1,105		1,105	6
47,375				2,584,000		2,584,000	7
					-183,872	-183,872	8
1				14		14	9
477				32,081		32,081	10
							11
	60,313	15,705					12
		3,768					13
	45,759	258,872					14
3,716,429	106,826	288,567	2,815,124	225,793,335	2,528,839	231,137,298	

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	Puget Sound Energy, Inc.	EX	-			
2	Sierra Pacific Power Company	EX	-			
3	Utah Associated Municipal Power System	EX	-			
4	Other Transactions					
5	Power Plant Test Power					
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.
	516						1
		10,222					2
	238						3
							4
					1,210,754	1,210,754	5
							6
							7
							8
							9
							10
							11
							12
							13
							14
3,716,429	106,826	288,567	2,815,124	225,793,335	2,528,839	231,137,298	

Schedule Page: 326 Line No.: 3 Column: a
The Tamarack Energy Partnership demand readings are taken from an electronic demand recorder provided by Idaho Power Co. The actual demand is not used in determining the cost of energy.

Schedule Page: 326 Line No.: 3 Column: e
Unavailable

Schedule Page: 326 Line No.: 3 Column: f
Unavailable

Schedule Page: 326 Line No.: 9 Column: e
Unavailable

Schedule Page: 326 Line No.: 9 Column: f
Unavailable

Schedule Page: 326.1 Line No.: 1 Column: b
Non Firm Purchases

Schedule Page: 326.1 Line No.: 2 Column: e
Unavailable

Schedule Page: 326.1 Line No.: 2 Column: f
Unavailable

Schedule Page: 326.1 Line No.: 8 Column: b
Non Firm Purchases

Schedule Page: 326.1 Line No.: 12 Column: e
Unavailable

Schedule Page: 326.1 Line No.: 12 Column: f
Unavailable

Schedule Page: 326.2 Line No.: 4 Column: e
Unavailable

Schedule Page: 326.2 Line No.: 4 Column: f
Unavailable

Schedule Page: 326.2 Line No.: 11 Column: e
Unavailable

Schedule Page: 326.2 Line No.: 11 Column: f
Unavailable

Schedule Page: 326.3 Line No.: 5 Column: a
Ida West, a subsidiary of Idaho Power Company, has partial ownership of these projects.

Schedule Page: 326.3 Line No.: 12 Column: b
Non Firm Purchases

Schedule Page: 326.4 Line No.: 4 Column: a
Ida West, a subsidiary of Idaho Power Company, has partial ownership of these projects.

Schedule Page: 326.4 Line No.: 5 Column: a
Ida West, a subsidiary of Idaho Power Company, has partial ownership of these projects.

Schedule Page: 326.4 Line No.: 6 Column: a
Ida West, a subsidiary of Idaho Power Company, has partial ownership of these projects.

Schedule Page: 326.4 Line No.: 12 Column: b
Non Firm Purchases

Schedule Page: 326.5 Line No.: 4 Column: b
Energy difference between scheduled and actual receipts from small power producers.

Schedule Page: 326.5 Line No.: 5 Column: b
Energy difference between mountain and pacific time schedules

Schedule Page: 326.6 Line No.: 4 Column: b
Spinning or Operating Reserves

Schedule Page: 326.6 Line No.: 6 Column: b
Financial Transmission Losses

Schedule Page: 326.6 Line No.: 10 Column: b
Non Firm Purchases

FOOTNOTE DATA

Schedule Page: 326.6 Line No.: 12 Column: b
Non Firm Purchases

Schedule Page: 326.7 Line No.: 6 Column: b
Non Firm Purchases

Schedule Page: 326.8 Line No.: 5 Column: b
Non Firm Purchases

Schedule Page: 326.9 Line No.: 3 Column: b
Financial Transmission Losses

Schedule Page: 326.9 Line No.: 5 Column: b
Non Firm Purchases

Schedule Page: 326.9 Line No.: 7 Column: b
Non Firm Purchases

Schedule Page: 326.9 Line No.: 10 Column: b
Non Firm Purchases

Schedule Page: 326.9 Line No.: 13 Column: b
Prudential Bache Commodities, LLC Futures Account Document, dated September 4, 2008.

Schedule Page: 326.10 Line No.: 3 Column: b
Unavailable

Schedule Page: 326.10 Line No.: 4 Column: b
Non Firm Purchases

Schedule Page: 326.10 Line No.: 9 Column: b
ISDA Master Agreement dated February 21, 2008.

Schedule Page: 326.10 Line No.: 12 Column: b
Non Firm Purchases

Schedule Page: 326.10 Line No.: 14 Column: b
Financial Transmission Losses

Schedule Page: 326.11 Line No.: 8 Column: b
Institutional Futures Client Account Agreement with UBS, dated March 8, 2006.

Schedule Page: 326.11 Line No.: 10 Column: b
Schedule 84 Net Metering

Schedule Page: 326.11 Line No.: 12 Column: b
Scheduled losses not removed with loss transactions.

Schedule Page: 326.11 Line No.: 13 Column: b
Scheduled losses not removed with loss transactions.

Schedule Page: 326.11 Line No.: 14 Column: b
Scheduled losses not removed with loss transactions.

Schedule Page: 326.12 Line No.: 1 Column: b
Scheduled losses not removed with loss transactions.

Schedule Page: 326.12 Line No.: 2 Column: b
Scheduled losses not removed with loss transactions.

Schedule Page: 326.12 Line No.: 3 Column: b
Scheduled losses not removed with loss transactions.

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/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	Bonneville Power Administration - OTEC	Bonneville Power Administration	Oregon Trails Electric Co-op	FNO
2	Bonneville Power Administration - OTEC			AD
3	Bonneville Power Administration - USBR	Bonneville Power Administration	United States Bureau of Rec	FNO
4	Bonneville Power Administration - USBR			AD
5	Bonneville Power Administration - Raft	Bonneville Power Administration	Raft River Electric Co-op	FNO
6	Bonneville Power Administration - Raft			AD
7	Bonneville Power Administration - PF	Bonneville Power Administration	Priority Firm Customers	FNO
8	Bonneville Power Administration - PF			AD
9	Milner Irrigation District	United States Bureau of Rec	Milner Irrigation District	OLF
10	City of Seattle	Seattle City Light	Bonneville Power Administration	OS
11	Cargill	Seattle City Light	Bonneville Power Administration	OS
12	PacifiCorp	PacifiCorp West	PacifiCorp West	FNO
13	PacifiCorp			AD
14	United States Bureau of Indian Affairs	Bonneville Power Administration	US Bureau of Indian Affairs	OS
15	Pacificorp Power Marketing	PacifiCorp West	PacifiCorp West	OS
16	Black Hills Power	PacifiCorp West	Bonneville Power Administration	NF
17	Black Hills Power	PacifiCorp West	Sierra Pacific Power	NF
18	Bonneville Power Admin.	Bonneville Power Administration	Bonneville Power Administration	NF
19	Bonneville Power Admin.	Bonneville Power Administration	Avista	NF
20	Bonneville Power Admin.	Bonneville Power Administration	Sierra Pacific Power	NF
21	Bonneville Power Admin.	Avista	Bonneville Power Administration	NF
22	Bonneville Power Admin.			AD
23	Cargill Power Markets (INCL REDIR)	PacifiCorp East	PacifiCorp West	NF
24	Cargill Power Markets (INCL REDIR)	PacifiCorp East	Bonneville Power Administration	NF
25	Cargill Power Markets (INCL REDIR)	PacifiCorp East	Sierra Pacific Power	NF
26	Cargill Power Markets (INCL REDIR)	PacifiCorp East	Sierra Pacific Power	SFP
27	Cargill Power Markets (INCL REDIR)	PacifiCorp East	PacifiCorp West	NF
28	Cargill Power Markets (INCL REDIR)	PacifiCorp East	PacifiCorp West	NF
29	Cargill Power Markets (INCL REDIR)	PacifiCorp East	NorthWestern/PacifiCorp East	NF
30	Cargill Power Markets (INCL REDIR)	PacifiCorp East	Bonneville Power Administration	NF
31	Cargill Power Markets (INCL REDIR)	PacifiCorp East	Bonneville Power Administration	SFP
32	Cargill Power Markets (INCL REDIR)	PacifiCorp East	Avista	NF
33	Cargill Power Markets (INCL REDIR)	PacifiCorp East	Sierra Pacific Power	NF
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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.
5				390,858	390,858	1
5						2
5				203,696	203,696	3
5						4
5				253,612	253,612	5
5						6
5				826,802	826,802	7
5						8
Legacy	Minidoka, Idaho	Various in Idaho		9,246	9,246	9
10				30,631	30,631	10
10				279,635	279,635	11
5				2,130	2,130	12
5						13
Legacy	LaGrande, Oregon	Various in Idaho		16,541	16,541	14
Legacy (440)	JBSN	ENPR		2,522	2,522	15
5	JBSN	LGBP		1,885	1,885	16
5	JBSN	M345		300	300	17
5	LGBP	LGBP		1,053	1,053	18
5	LGBP	LOLO		4,667	4,667	19
5	LGBP	M345		1,120	1,120	20
5	LOLO	LGBP		5,386	5,386	21
5						22
5	BOBR	JBSN		30	30	23
5	BOBR	LGBP		20,336	20,336	24
5	BOBR	M345		48,898	48,898	25
5	BOBR	M345		20,527	20,527	26
5	BORA	ENPR		7,066	7,066	27
5	BORA	ENPR		11,784	11,784	28
5	BORA	JEFF		25	25	29
5	BORA	LGBP		16,393	16,393	30
5	BORA	LGBP		1,280	1,280	31
5	BORA	LOLO		24	24	32
5	BORA	M345		901	901	33
						34
			0	**5,036,540**	**5,036,540**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/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	Cargill Power Markets (INCL REDIR)	PacifiCorp East	Sierra Pacific Power	SFP
2	Cargill Power Markets (INCL REDIR)	PacifiCorp East	Bonneville Power Administration	NF
3	Cargill Power Markets (INCL REDIR)	PacifiCorp East	NorthWestern/PacifiCorp East	SFP
4	Cargill Power Markets (INCL REDIR)	PacifiCorp West	PacifiCorp East	NF
5	Cargill Power Markets (INCL REDIR)	PacifiCorp West	PacifiCorp East	SFP
6	Cargill Power Markets (INCL REDIR)	PacifiCorp West	PacifiCorp East	NF
7	Cargill Power Markets (INCL REDIR)	PacifiCorp West	Sierra Pacific Power	NF
8	Cargill Power Markets (INCL REDIR)	NorthWestern/PacifiCorp East	PacifiCorp East	NF
9	Cargill Power Markets (INCL REDIR)	NorthWestern/PacifiCorp East	PacifiCorp East	NF
10	Cargill Power Markets (INCL REDIR)	PacifiCorp West	PacifiCorp East	NF
11	Cargill Power Markets (INCL REDIR)	PacifiCorp West	PacifiCorp West	NF
12	Cargill Power Markets (INCL REDIR)	PacifiCorp West	Idaho Power Company	NF
13	Cargill Power Markets (INCL REDIR)	PacifiCorp West	Bonneville Power Administration	NF
14	Cargill Power Markets (INCL REDIR)	PacifiCorp West	Sierra Pacific Power	NF
15	Cargill Power Markets (INCL REDIR)	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
16	Cargill Power Markets (INCL REDIR)	Bonneville Power Administration	PacifiCorp East	NF
17	Cargill Power Markets (INCL REDIR)	Bonneville Power Administration	PacifiCorp East	NF
18	Cargill Power Markets (INCL REDIR)	Bonneville Power Administration	PacifiCorp West	NF
19	Cargill Power Markets (INCL REDIR)	Bonneville Power Administration	Sierra Pacific Power	NF
20	Cargill Power Markets (INCL REDIR)	Avista	PacifiCorp East	NF
21	Cargill Power Markets (INCL REDIR)	Avista	PacifiCorp East	SFP
22	Cargill Power Markets (INCL REDIR)	Avista	PacifiCorp West	NF
23	Cargill Power Markets (INCL REDIR)	Avista	Sierra Pacific Power	NF
24	Cargill Power Markets (INCL REDIR)	Sierra Pacific Power	PacifiCorp East	NF
25	Cargill Power Markets (INCL REDIR)	Sierra Pacific Power	PacifiCorp East	SFP
26	Cargill Power Markets (INCL REDIR)	Sierra Pacific Power	PacifiCorp East	NF
27	Cargill Power Markets (INCL REDIR)	Sierra Pacific Power	PacifiCorp East	SFP
28	Cargill Power Markets (INCL REDIR)	Sierra Pacific Power	PacifiCorp East	SFP
29	Cargill Power Markets (INCL REDIR)	Sierra Pacific Power	Idaho Power Company	SFP
30	Cargill Power Markets (INCL REDIR)	Sierra Pacific Power	Bonneville Power Administration	NF
31	Cargill Power Markets (INCL REDIR)	Sierra Pacific Power	Bonneville Power Administration	SFP
32	Cargill Power Markets (INCL REDIR)	Sierra Pacific Power	Bonneville Power Administration	NF
33	Cargill Power Markets (INCL REDIR)	Sierra Pacific Power	Avista	NF
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
5	BORA	M345		192	192	1
5	BORA	PF		220	220	2
5	BRDY	HTSP		170	170	3
5	ENPR	BOBR		139,253	139,253	4
5	ENPR	BOBR		951	951	5
5	ENPR	BORA		61,103	61,103	6
5	ENPR	M345		50	50	7
5	HTSP	BOBR		4,398	4,398	8
5	HTSP	BRDY		106	106	9
5	JBSN	BRDY		131	131	10
5	JBSN	ENPR		7	7	11
5	JBSN	IPCO		84	84	12
5	JBSN	LGBP		8,270	8,270	13
5	JBSN	M345		6,281	6,281	14
5	JEFF	M345		36	36	15
5	LGBP	BOBR		1,837	1,837	16
5	LGBP	BORA		88	88	17
5	LGBP	JBSN		1,324	1,324	18
5	LGBP	M345		10,299	10,299	19
5	LOLO	BOBR		8,290	8,290	20
5	LOLO	BOBR		4,511	4,511	21
5	LOLO	JBSN		195	195	22
5	LOLO	M345		801	801	23
5	LYPK	BOBR		24,583	24,583	24
5	LYPK	BOBR		14,789	14,789	25
5	LYPK	BORA		73,143	73,143	26
5	LYPK	BORA		1,232	1,232	27
5	LYPK	BRDY		170	170	28
5	LYPK	IPCO		566	566	29
5	LYPK	LGBP		2,540	2,540	30
5	LYPK	LGBP		696	696	31
5	LYPK	LGBP		15,242	15,242	32
5	LYPK	LOLO		150	150	33
						34
			0	5,036,540	5,036,540	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/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	Cargill Power Markets (INCL REDIR)	Sierra Pacific Power	Sierra Pacific Power	NF
2	Cargill Power Markets (INCL REDIR)	Sierra Pacific Power	Sierra Pacific Power	SFP
3	Cargill Power Markets (INCL REDIR)	Sierra Pacific Power	PacifiCorp East	NF
4	Cargill Power Markets (INCL REDIR)	Sierra Pacific Power	PacifiCorp East	NF
5	Cargill Power Markets (INCL REDIR)	Sierra Pacific Power	PacifiCorp East	NF
6	Cargill Power Markets (INCL REDIR)	Sierra Pacific Power	PacifiCorp West	NF
7	Cargill Power Markets (INCL REDIR)	Sierra Pacific Power	Bonneville Power Administration	NF
8	Cargill Power Markets (INCL REDIR)	Sierra Pacific Power	Bonneville Power Administration	NF
9	Cargill Power Markets (INCL REDIR)	PacifiCorp East	PacifiCorp East	NF
10	Cargill Power Markets			AD
11	Constellation Energy	PacifiCorp East	Sierra Pacific Power	NF
12	Constellation Energy	PacifiCorp East	Sierra Pacific Power	SFP
13	Constellation Energy	NorthWestern/PacifiCorp East	PacifiCorp East	NF
14	Constellation Energy	Avista	Sierra Pacific Power	NF
15	Constellation Energy	Avista	Sierra Pacific Power	SFP
16	Constellation Energy	Sierra Pacific Power	PacifiCorp East	NF
17	Constellation Energy	PacifiCorp East	PacifiCorp East	NF
18	Constellation Energy	Idaho Power Company	PacifiCorp East	NF
19	Constellation Energy	Idaho Power Company	Sierra Pacific Power	NF
20	Coral Power	PacifiCorp East	Sierra Pacific Power	NF
21	Coral Power	PacifiCorp East	PacifiCorp West	NF
22	Coral Power	PacifiCorp East	Bonneville Power Administration	NF
23	Coral Power	PacifiCorp East	Avista	NF
24	Coral Power	PacifiCorp East	Sierra Pacific Power	NF
25	Coral Power	PacifiCorp East	Sierra Pacific Power	NF
26	Coral Power	PacifiCorp West	Sierra Pacific Power	NF
27	Coral Power	NorthWestern/PacifiCorp East	PacifiCorp East	NF
28	Coral Power	PacifiCorp West	Bonneville Power Administration	NF
29	Coral Power	PacifiCorp West	Sierra Pacific Power	NF
30	Coral Power	Idaho Power Company	Sierra Pacific Power	NF
31	Coral Power	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
32	Coral Power	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
33	Coral Power	Bonneville Power Administration	PacifiCorp East	NF
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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.
5	LYPK	M345		67,363	67,363	1
5	LYPK	M345		75,098	75,098	2
5	M345	BOBR		22	22	3
5	M345	BORA		42	42	4
5	M345	BRDY		65	65	5
5	M345	ENPR		305	305	6
5	M345	LGBP		619	619	7
5	M345	PF		6	6	8
5	MLCK	BOBR		1,024	1,024	9
5						10
5	BOBR	M345		14,131	14,131	11
5	BOBR	M345		1,180	1,180	12
5	HTSP	BOBR		1,003	1,003	13
5	LOLO	M345		42,063	42,063	14
5	LOLO	M345		13,667	13,667	15
5	LYPK	BOBR		80	80	16
5	MLCK	BOBR		400	400	17
5	OBBLPR	BOBR		400	400	18
5	OBBLPR	M345		864	864	19
5	BOBR	M345		28,685	28,685	20
5	BORA	ENPR		50	50	21
5	BORA	LGBP		87	87	22
5	BORA	LOLO		40	40	23
5	BORA	M345		4,797	4,797	24
5	BRDY	M345		940	940	25
5	ENPR	M345		90	90	26
5	HTSP	BRDY		295	295	27
5	JBSN	LGBP		802	802	28
5	JBSN	M345		232	232	29
5	JBWT	M345		26,488	26,488	30
5	JEFF	LGBP		1,338	1,338	31
5	JEFF	M345		478	478	32
5	LGBP	BOBR		880	880	33
						34
			0	5,036,540	5,036,540	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/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	Coral Power	Bonneville Power Administration	Sierra Pacific Power	NF
2	Coral Power	Avista	PacifiCorp East	NF
3	Coral Power	Avista	Sierra Pacific Power	NF
4	Coral Power	Sierra Pacific Power	Bonneville Power Administration	NF
5	Coral Power	Sierra Pacific Power	Bonneville Power Administration	NF
6	Coral Power	PacifiCorp East	PacifiCorp East	NF
7	Coral Power	PacifiCorp East	PacifiCorp East	NF
8	Coral Power			AD
9	Highland Energy	PacifiCorp East	Bonneville Power Administration	NF
10	Highland Energy	PacifiCorp East	Bonneville Power Administration	NF
11	Integrys Energy	PacifiCorp West	Bonneville Power Administration	NF
12	Integrys Energy	Bonneville Power Administration	Sierra Pacific Power	NF
13	Morgan Stanley Capital Grp (INCL REDIR)	PacifiCorp East	Bonneville Power Administration	NF
14	Morgan Stanley Capital Grp (INCL REDIR)	PacifiCorp East	Sierra Pacific Power	NF
15	Morgan Stanley Capital Grp (INCL REDIR)	PacifiCorp East	PacifiCorp West	NF
16	Morgan Stanley Capital Grp (INCL REDIR)	PacifiCorp East	Bonneville Power Administration	NF
17	Morgan Stanley Capital Grp (INCL REDIR)	PacifiCorp East	Bonneville Power Administration	NF
18	Morgan Stanley Capital Grp (INCL REDIR)	PacifiCorp East	PacifiCorp West	NF
19	Morgan Stanley Capital Grp (INCL REDIR)	PacifiCorp East	NorthWestern/PacifiCorp East	NF
20	Morgan Stanley Capital Grp (INCL REDIR)	PacifiCorp East	Bonneville Power Administration	NF
21	Morgan Stanley Capital Grp (INCL REDIR)	PacifiCorp West	PacifiCorp East	NF
22	Morgan Stanley Capital Grp (INCL REDIR)	PacifiCorp West	PacifiCorp East	NF
23	Morgan Stanley Capital Grp (INCL REDIR)	PacifiCorp West	Sierra Pacific Power	NF
24	Morgan Stanley Capital Grp (INCL REDIR)	NorthWestern/PacifiCorp East	PacifiCorp East	NF
25	Morgan Stanley Capital Grp (INCL REDIR)	NorthWestern/PacifiCorp East	PacifiCorp East	NF
26	Morgan Stanley Capital Grp (INCL REDIR)	PacifiCorp West	Sierra Pacific Power	NF
27	Morgan Stanley Capital Grp (INCL REDIR)	PacifiCorp West	PacifiCorp West	NF
28	Morgan Stanley Capital Grp (INCL REDIR)	PacifiCorp West	Bonneville Power Administration	NF
29	Morgan Stanley Capital Grp (INCL REDIR)	Bonneville Power Administration	PacifiCorp East	NF
30	Morgan Stanley Capital Grp (INCL REDIR)	Bonneville Power Administration	PacifiCorp East	NF
31	Morgan Stanley Capital Grp (INCL REDIR)	Bonneville Power Administration	PacifiCorp East	NF
32	Morgan Stanley Capital Grp (INCL REDIR)	Bonneville Power Administration	PacifiCorp West	NF
33	Morgan Stanley Capital Grp (INCL REDIR)	Bonneville Power Administration	Sierra Pacific Power	NF
34				
	TOTAL			

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

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
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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.
5	LGBP	M345		10,202	10,202	1
5	LOLO	BOBR		65	65	2
5	LOLO	M345		642	642	3
5	LYPK	LGBP		733	733	4
5	M345	LGBP		4,613	4,613	5
5	MLCK	BOBR		67	67	6
5	MLCK	BRDY		7,592	7,592	7
5						8
5	BOBR	LGBP		20	20	9
5	BORA	LGBP		87	87	10
5	JBSN	LGBP		125	125	11
5	LGBP	M345		25	25	12
5	BOBR	LGBP		2,813	2,813	13
5	BOBR	M345		6,184	6,184	14
5	BORA	ENPR		1,169	1,169	15
5	BORA	LGBP		123	123	16
5	BORA	LGBP		210	210	17
5	BRDY	ENPR		783	783	18
5	BRDY	HTSP		49	49	19
5	BRDY	LGBP		3,677	3,677	20
5	ENPR	BOBR		898	898	21
5	ENPR	BRDY		1,079	1,079	22
5	ENPR	M345		300	300	23
5	HTSP	BOBR		210	210	24
5	HTSP	BRDY		375	375	25
5	JBSN	M345		570	570	26
5	JBSN	ENPR		90	90	27
5	JBSN	LGBP		8,878	8,878	28
5	LGBP	BOBR		2,382	2,382	29
5	LGBP	BORA		1,002	1,002	30
5	LGBP	BRDY		2,988	2,988	31
5	LGBP	JBSN		415	415	32
5	LGBP	M345		428	428	33
						34
			0	5,036,540	5,036,540	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/Q4

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

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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	Morgan Stanley Capital Grp (INCL REDIR)	Avista	PacifiCorp East	NF
2	Morgan Stanley Capital Grp (INCL REDIR)	Avista	PacifiCorp West	NF
3	Morgan Stanley Capital Grp (INCL REDIR)	Avista	Sierra Pacific Power	NF
4	Morgan Stanley Capital Grp (INCL REDIR)	Sierra Pacific Power	Bonneville Power Administration	NF
5	Morgan Stanley Capital Grp (INCL REDIR)	PacifiCorp East	PacifiCorp East	NF
6	Morgan Stanley Capital Grp			AD
7	Northwestern Energy	PacifiCorp East	PacifiCorp East	SFP
8	Pacificorp Power Marketing	PacifiCorp East	PacifiCorp East	NF
9	Pacificorp Power Marketing	PacifiCorp East	PacifiCorp West	NF
10	Pacificorp Power Marketing	PacifiCorp East	Sierra Pacific Power	NF
11	Pacificorp Power Marketing	PacifiCorp East	PacifiCorp West	NF
12	Pacificorp Power Marketing	PacifiCorp East	PacifiCorp West	NF
13	Pacificorp Power Marketing	PacifiCorp East	PacifiCorp East	NF
14	Pacificorp Power Marketing	PacifiCorp East	PacifiCorp West	NF
15	Pacificorp Power Marketing	PacifiCorp West	PacifiCorp East	NF
16	Pacificorp Power Marketing	PacifiCorp West	PacifiCorp East	SFP
17	Pacificorp Power Marketing	PacifiCorp West	PacifiCorp East	NF
18	Pacificorp Power Marketing	PacifiCorp West	PacifiCorp East	NF
19	Pacificorp Power Marketing	Idaho Power Company	PacifiCorp West	NF
20	Pacificorp Power Marketing	PacifiCorp West	PacifiCorp East	NF
21	Pacificorp Power Marketing	PacifiCorp West	PacifiCorp East	SFP
22	Pacificorp Power Marketing	PacifiCorp West	Sierra Pacific Power	NF
23	Pacificorp Power Marketing	Idaho Power Company	PacifiCorp East	NF
24	Pacificorp Power Marketing	Idaho Power Company	PacifiCorp East	SFP
25	Pacificorp Power Marketing	Idaho Power Company	PacifiCorp East	NF
26	Pacificorp Power Marketing	Idaho Power Company	PacifiCorp East	LFP
27	Pacificorp Power Marketing	Idaho Power Company	PacifiCorp East	NF
28	Pacificorp Power Marketing	Avista	PacifiCorp West	NF
29	Pacificorp Power Marketing			AD
30	Portland General Electric	PacifiCorp East	Bonneville Power Administration	NF
31	Portland General Electric	PacifiCorp East	Bonneville Power Administration	NF
32	Portland General Electric	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
33	Portland General Electric	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
34				
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/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.
5	LOLO	BOBR		118	118	1
5	LOLO	JBSN		42	42	2
5	LOLO	M345		274	274	3
5	M345	LGBP		757	757	4
5	MLCK	BRDY		5,560	5,560	5
5						6
5	BRDY	LOLO		126	126	7
5	BOBR	BOBR		170	170	8
5	BOBR	ENPR		41,744	41,744	9
5	BOBR	M345		1,200	1,200	10
5	BORA	ENPR		62,592	62,592	11
5	BORA	ENPR		11,091	11,091	12
5	BRDY	BRDY		142	142	13
5	BRDY	ENPR		6,770	6,770	14
5	ENPR	BOBR		29,610	29,610	15
5	ENPR	BOBR		875	875	16
5	ENPR	BORA		950	950	17
5	ENPR	BRDY		2,065	2,065	18
5	HCPR	ENPR		59	59	19
5	JBSN	BOBR		52,500	52,500	20
5	JBSN	BOBR		10,733	10,733	21
5	JBSN	M345		4,885	4,885	22
5	JBWT	BOBR		76,576	76,576	23
5	JBWT	BOBR		12,058	12,058	24
5	JBWT	BORA		115,937	115,937	25
5	JBWT	BORA		31,992	31,992	26
5	JBWT	BRDY		266,273	266,273	27
5	LOLO	ENPR		961	961	28
5						29
5	BOBR	LGBP		355	355	30
5	BORA	LGBP		539	539	31
5	HTSP	LGBP		120	120	32
5	JEFF	LGBP		9,407	9,407	33
						34
			0	5,036,540	5,036,540	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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	Portland General Electric	Bonneville Power Administration	Idaho Power Company	NF
2	Portland General Electric	Sierra Pacific Power	Bonneville Power Administration	NF
3	Portland General Electric	PacifiCorp East	PacifiCorp East	NF
4	Portland General Electric			AD
5	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp East	PacifiCorp West	NF
6	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp East	NorthWestern/PacifiCorp East	NF
7	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp East	PacifiCorp West	SFP
8	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp East	Bonneville Power Administration	NF
9	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp East	Bonneville Power Administration	SFP
10	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp East	Sierra Pacific Power	SFP
11	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp East	PacifiCorp East	NF
12	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp East	PacifiCorp West	NF
13	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp East	Bonneville Power Administration	NF
14	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp East	Bonneville Power Administration	SFP
15	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp East	Avista	NF
16	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp East	Sierra Pacific Power	NF
17	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp East	PacifiCorp West	NF
18	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp East	Bonneville Power Administration	NF
19	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp East	Bonneville Power Administration	SFP
20	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp East	Avista	NF
21	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp West	PacifiCorp East	NF
22	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp West	PacifiCorp East	SFP
23	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp West	PacifiCorp East	NF
24	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp West	PacifiCorp East	SFP
25	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp West	PacifiCorp East	NF
26	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp West	PacifiCorp West	NF
27	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp West	Sierra Pacific Power	NF
28	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp West	Sierra Pacific Power	SFP
29	Powerex Corp. (INCLUDES REDIRECTS)	NorthWestern/PacifiCorp East	PacifiCorp East	NF
30	Powerex Corp. (INCLUDES REDIRECTS)	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
31	Powerex Corp. (INCLUDES REDIRECTS)	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
32	Powerex Corp. (INCLUDES REDIRECTS)	NorthWestern/PacifiCorp East	Sierra Pacific Power	SFP
33	Powerex Corp. (INCLUDES REDIRECTS)	NorthWestern/PacifiCorp East	PacifiCorp East	NF
34				
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/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.
5	LGBP	IPCO		34	34	1
5	M345	LGBP		644	644	2
5	MLCK	BRDY		8,847	8,847	3
5						4
5	BOBR	ENPR		121	121	5
5	BOBR	HTSP		464	464	6
5	BOBR	JBSN		301	301	7
5	BOBR	LGBP		43,342	43,342	8
5	BOBR	LGBP		99	99	9
5	BOBR	M345		41,053	41,053	10
5	BORA	BRDY		1,933	1,933	11
5	BORA	ENPR		1,768	1,768	12
5	BORA	LGBP		66,149	66,149	13
5	BORA	LGBP		1,200	1,200	14
5	BORA	LOLO		3,172	3,172	15
5	BORA	M345		1,009	1,009	16
5	BRDY	ENPR		15	15	17
5	BRDY	LGBP		4,671	4,671	18
5	BRDY	LGBP		5,266	5,266	19
5	BRDY	LOLO		257	257	20
5	ENPR	BOBR		90,322	90,322	21
5	ENPR	BOBR		12,991	12,991	22
5	ENPR	BORA		19,360	19,360	23
5	ENPR	BORA		3,545	3,545	24
5	ENPR	BRDY		16,702	16,702	25
5	ENPR	JBSN		176	176	26
5	ENPR	M345		2,612	2,612	27
5	ENPR	M345		61,042	61,042	28
5	HTSP	BOBR		27,937	27,937	29
5	HTSP	BOBR		482	482	30
5	HTSP	M345		2,620	2,620	31
5	HTSP	M345		30,444	30,444	32
5	HTSP	BRDY		3,589	3,589	33
						34
			0	5,036,540	5,036,540	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp West	PacifiCorp East	NF
2	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp West	PacifiCorp West	NF
3	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp West	NorthWestern/PacifiCorp East	NF
4	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp West	Bonneville Power Administration	NF
5	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp West	Avista	NF
6	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp West	Sierra Pacific Power	NF
7	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp West	PacifiCorp West	NF
8	Powerex Corp. (INCLUDES REDIRECTS)	Idaho Power Company	PacifiCorp West	NF
9	Powerex Corp. (INCLUDES REDIRECTS)	Idaho Power Company	Bonneville Power Administration	NF
10	Powerex Corp. (INCLUDES REDIRECTS)	Idaho Power Company	Avista	NF
11	Powerex Corp. (INCLUDES REDIRECTS)	Idaho Power Company	Sierra Pacific Power	NF
12	Powerex Corp. (INCLUDES REDIRECTS)	NorthWestern/PacifiCorp East	PacifiCorp East	NF
13	Powerex Corp. (INCLUDES REDIRECTS)	NorthWestern/PacifiCorp East	PacifiCorp East	NF
14	Powerex Corp. (INCLUDES REDIRECTS)	NorthWestern/PacifiCorp East	PacifiCorp West	NF
15	Powerex Corp. (INCLUDES REDIRECTS)	NorthWestern/PacifiCorp East	PacifiCorp West	NF
16	Powerex Corp. (INCLUDES REDIRECTS)	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
17	Powerex Corp. (INCLUDES REDIRECTS)	NorthWestern/PacifiCorp East	Avista	NF
18	Powerex Corp. (INCLUDES REDIRECTS)	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
19	Powerex Corp. (INCLUDES REDIRECTS)	Bonneville Power Administration	PacifiCorp East	NF
20	Powerex Corp. (INCLUDES REDIRECTS)	Bonneville Power Administration	PacifiCorp East	SFP
21	Powerex Corp. (INCLUDES REDIRECTS)	Bonneville Power Administration	PacifiCorp East	NF
22	Powerex Corp. (INCLUDES REDIRECTS)	Bonneville Power Administration	PacifiCorp East	NF
23	Powerex Corp. (INCLUDES REDIRECTS)	Bonneville Power Administration	PacifiCorp West	NF
24	Powerex Corp. (INCLUDES REDIRECTS)	Bonneville Power Administration	Sierra Pacific Power	NF
25	Powerex Corp. (INCLUDES REDIRECTS)	Bonneville Power Administration	Sierra Pacific Power	SFP
26	Powerex Corp. (INCLUDES REDIRECTS)	Avista	PacifiCorp East	NF
27	Powerex Corp. (INCLUDES REDIRECTS)	Avista	PacifiCorp East	SFP
28	Powerex Corp. (INCLUDES REDIRECTS)	Avista	PacifiCorp East	NF
29	Powerex Corp. (INCLUDES REDIRECTS)	Avista	PacifiCorp West	NF
30	Powerex Corp. (INCLUDES REDIRECTS)	Avista	PacifiCorp West	NF
31	Powerex Corp. (INCLUDES REDIRECTS)	Avista	Bonneville Power Administration	NF
32	Powerex Corp. (INCLUDES REDIRECTS)	Avista	Sierra Pacific Power	NF
33	Powerex Corp. (INCLUDES REDIRECTS)	Avista	Sierra Pacific Power	SFP
34				
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/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.
5	JBSN	BRDY		759	759	1
5	JBSN	ENPR		2,202	2,202	2
5	JBSN	JEFF		12	12	3
5	JBSN	LGBP		56,155	56,155	4
5	JBSN	LOLO		218	218	5
5	JBSN	M345		3,673	3,673	6
5	JBSN	M500		450	450	7
5	JBWT	ENPR		363	363	8
5	JBWT	LGBP		9,769	9,769	9
5	JBWT	LOLO		82	82	10
5	JBWT	M345		130	130	11
5	JEFF	BOBR		2,542	2,542	12
5	JEFF	BORA		226	226	13
5	JEFF	ENPR		29	29	14
5	JEFF	JBSN		607	607	15
5	JEFF	LGBP		1,620	1,620	16
5	JEFF	LOLO		195	195	17
5	JEFF	M345		2,350	2,350	18
5	LGBP	BOBR		10,225	10,225	19
5	LGBP	BOBR		240	240	20
5	LGBP	BORA		21,515	21,515	21
5	LGBP	BRDY		46	46	22
5	LGBP	JBSN		3,837	3,837	23
5	LGBP	M345		20,566	20,566	24
5	LGBP	M345		8,196	8,196	25
5	LOLO	BOBR		992	992	26
5	LOLO	BOBR		5,559	5,559	27
5	LOLO	BORA		2,015	2,015	28
5	LOLO	ENPR		30	30	29
5	LOLO	JBSN		172	172	30
5	LOLO	LGBP		113	113	31
5	LOLO	M345		27,590	27,590	32
5	LOLO	M345		5,354	5,354	33
						34
			0	**5,036,540**	**5,036,540**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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.
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3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Powerex Corp. (INCLUDES REDIRECTS)	Sierra Pacific Power	PacifiCorp East	NF
2	Powerex Corp. (INCLUDES REDIRECTS)	Sierra Pacific Power	Bonneville Power Administration	NF
3	Powerex Corp. (INCLUDES REDIRECTS)	Sierra Pacific Power	Sierra Pacific Power	NF
4	Powerex Corp. (INCLUDES REDIRECTS)	Sierra Pacific Power	PacifiCorp East	NF
5	Powerex Corp. (INCLUDES REDIRECTS)	Sierra Pacific Power	PacifiCorp West	NF
6	Powerex Corp. (INCLUDES REDIRECTS)	Sierra Pacific Power	Bonneville Power Administration	NF
7	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp East	PacifiCorp East	NF
8	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp East	PacifiCorp East	NF
9	Powerex Corp.			AD
10	PPL EnergyPlus, LLC (EPLU)	PacifiCorp East	Bonneville Power Administration	NF
11	PPL EnergyPlus, LLC (EPLU)	PacifiCorp East	Bonneville Power Administration	NF
12	PPL EnergyPlus, LLC (EPLU)	NorthWestern/PacifiCorp East	PacifiCorp East	NF
13	PPL EnergyPlus, LLC (EPLU)	NorthWestern/PacifiCorp East	PacifiCorp East	NF
14	PPL EnergyPlus, LLC (EPLU)	PacifiCorp West	Bonneville Power Administration	NF
15	PPL EnergyPlus, LLC (EPLU)	NorthWestern/PacifiCorp East	PacifiCorp East	NF
16	PPL EnergyPlus, LLC (EPLU)	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
17	PPL EnergyPlus, LLC (EPLU)	NorthWestern/PacifiCorp East	Avista	NF
18	PPL EnergyPlus, LLC (EPLU)	PacifiCorp East	PacifiCorp East	NF
19	PPL EnergyPlus, LLC (EPLU)	PacifiCorp East	PacifiCorp East	NF
20	PPL EnergyPlus, LLC (EPLU)			AD
21	PPM Energy	PacifiCorp East	Bonneville Power Administration	NF
22	PPM Energy	PacifiCorp East	Bonneville Power Administration	NF
23	PPM Energy	PacifiCorp West	Bonneville Power Administration	NF
24	PPM Energy	Bonneville Power Administration	PacifiCorp East	NF
25	PPM Energy	Sierra Pacific Power	Bonneville Power Administration	NF
26	PPM Energy			AD
27	Puget Sound Energy	NorthWestern/PacifiCorp East	PacifiCorp East	NF
28	Puget Sound Energy	NorthWestern/PacifiCorp East	PacifiCorp East	NF
29	Puget Sound Energy	PacifiCorp East	PacifiCorp East	NF
30	Puget Sound Energy			AD
31	Rainbow Energy Marketing Company	PacifiCorp East	Sierra Pacific Power	NF
32	Rainbow Energy Marketing Company	PacifiCorp East	Sierra Pacific Power	SFP
33	Rainbow Energy Marketing Company	PacifiCorp West	Sierra Pacific Power	SFP
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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.
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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)	MegaWatt Hours Delivered (j)	Line No.
5	LYPK	BOBR		128	128	1
5	LYPK	LGBP		20	20	2
5	LYPK	M345		48	48	3
5	M345	BOBR		1,152	1,152	4
5	M345	ENPR		14	14	5
5	M345	LGBP		11,743	11,743	6
5	MLCK	BOBR		11,027	11,027	7
5	MLCK	BRDY		6,058	6,058	8
5						9
5	BOBR	LGBP		983	983	10
5	BRDY	LGBP		108	108	11
5	HTSP	BOBR		326	326	12
5	HTSP	BRDY		2	2	13
5	JBSN	LGBP		133	133	14
5	JEFF	BOBR		115	115	15
5	JEFF	LGBP		10,707	10,707	16
5	JEFF	LOLO		750	750	17
5	MLCK	BOBR		8,029	8,029	18
5	MLCK	BRDY		14,503	14,503	19
5						20
5	BOBR	LGBP		2,542	2,542	21
5	BORA	LGBP		667	667	22
5	ENPR	LGBP		80	80	23
5	LGBP	BOBR		1,135	1,135	24
5	M345	LGBP		100	100	25
5						26
5	HTSP	BOBR		1,032	1,032	27
5	HTSP	BRDY		435	435	28
5	MLCK	BRDY		12,854	12,854	29
5						30
5	BOBR	M345		2,622	2,622	31
5	BOBR	M345		32,797	32,797	32
5	ENPR	M345		1,377	1,377	33
						34
			0	5,036,540	5,036,540	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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	Rainbow Energy Marketing Company	NorthWestern/PacifiCorp East	PacifiCorp East	NF
2	Rainbow Energy Marketing Company	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
3	Rainbow Energy Marketing Company	NorthWestern/PacifiCorp East	PacifiCorp East	NF
4	Rainbow Energy Marketing Company	PacifiCorp West	NorthWestern/PacifiCorp East	NF
5	Rainbow Energy Marketing Company	PacifiCorp West	Bonneville Power Administration	NF
6	Rainbow Energy Marketing Company	PacifiCorp West	Sierra Pacific Power	NF
7	Rainbow Energy Marketing Company	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
8	Rainbow Energy Marketing Company	NorthWestern/PacifiCorp East	Avista	NF
9	Rainbow Energy Marketing Company	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
10	Rainbow Energy Marketing Company	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
11	Rainbow Energy Marketing Company	Bonneville Power Administration	PacifiCorp West	NF
12	Rainbow Energy Marketing Company	Bonneville Power Administration	Sierra Pacific Power	NF
13	Rainbow Energy Marketing Company	Bonneville Power Administration	Sierra Pacific Power	SFP
14	Rainbow Energy Marketing Company	Avista	PacifiCorp West	NF
15	Rainbow Energy Marketing Company	Avista	Sierra Pacific Power	NF
16	Rainbow Energy Marketing Company	Avista	Sierra Pacific Power	SFP
17	Rainbow Energy Marketing Company	Sierra Pacific Power	Bonneville Power Administration	NF
18	Rainbow Energy Marketing Company	PacifiCorp East	PacifiCorp East	NF
19	Rainbow Energy Marketing Company	PacifiCorp East	PacifiCorp East	NF
20	Seattle City Light			NF
21	Sempra Energy Trading Corp	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
22	Sempra Energy Trading Corp	PacifiCorp East	PacifiCorp East	NF
23	Sempra Energy Trading Corp			LFP
24	Sierra Pacific Power (INCL REDIR)	PacifiCorp East	PacifiCorp West	NF
25	Sierra Pacific Power (INCL REDIR)	PacifiCorp East	Sierra Pacific Power	NF
26	Sierra Pacific Power (INCL REDIR)	PacifiCorp East	Sierra Pacific Power	SFP
27	Sierra Pacific Power (INCL REDIR)	PacifiCorp East	Bonneville Power Administration	NF
28	Sierra Pacific Power (INCL REDIR)	PacifiCorp East	Sierra Pacific Power	NF
29	Sierra Pacific Power (INCL REDIR)	PacifiCorp East	Sierra Pacific Power	SFP
30	Sierra Pacific Power (INCL REDIR)	PacifiCorp West	Sierra Pacific Power	NF
31	Sierra Pacific Power (INCL REDIR)	NorthWestern/PacifiCorp East	PacifiCorp East	NF
32	Sierra Pacific Power (INCL REDIR)	NorthWestern/PacifiCorp East	PacifiCorp East	NF
33	Sierra Pacific Power (INCL REDIR)	PacifiCorp West	PacifiCorp East	NF
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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.
5	HTSP	BOBR		10,918	10,918	1
5	HTSP	BOBR		3,687	3,687	2
5	HTSP	BRDY		3,592	3,592	3
5	JBSN	JEFF		650	650	4
5	JBSN	LGBP		52	52	5
5	JBSN	M345		131	131	6
5	JEFF	LGBP		720	720	7
5	JEFF	LOLO		272	272	8
5	JEFF	M345		852	852	9
5	JEFF	OTEC		25	25	10
5	LGBP	JBSN		571	571	11
5	LGBP	M345		5,749	5,749	12
5	LGBP	M345		16,215	16,215	13
5	LOLO	JBSN		25	25	14
5	LOLO	M345		25,041	25,041	15
5	LOLO	M345		43,397	43,397	16
5	M345	LGBP		1,046	1,046	17
5	MLCK	BOBR		240	240	18
5	MLCK	BRDY		400	400	19
5						20
5	HTSP	BOBR		16,644	16,644	21
5	MLCK	BOBR		25	25	22
5						23
5	BOBR	JBSN		25	25	24
5	BOBR	M345		10,048	10,048	25
5	BOBR	M345		49,165	49,165	26
5	BORA	LGBP		2,200	2,200	27
5	BORA	M345		11,779	11,779	28
5	BORA	M345		5,200	5,200	29
5	ENPR	M345		1,567	1,567	30
5	HTSP	BOBR		48,434	48,434	31
5	HTSP	BRDY		2,110	2,110	32
5	JBSN	BOBR		600	600	33
						34
			0	**5,036,540**	**5,036,540**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/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	Sierra Pacific Power (INCL REDIR)	PacifiCorp West	PacifiCorp East	NF
2	Sierra Pacific Power (INCL REDIR)	PacifiCorp West	Idaho Power Company	NF
3	Sierra Pacific Power (INCL REDIR)	PacifiCorp West	Bonneville Power Administration	NF
4	Sierra Pacific Power (INCL REDIR)	PacifiCorp West	Sierra Pacific Power	NF
5	Sierra Pacific Power (INCL REDIR)	NorthWestern/PacifiCorp East	PacifiCorp East	NF
6	Sierra Pacific Power (INCL REDIR)	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
7	Sierra Pacific Power (INCL REDIR)	Bonneville Power Administration	PacifiCorp East	NF
8	Sierra Pacific Power (INCL REDIR)	Bonneville Power Administration	Sierra Pacific Power	NF
9	Sierra Pacific Power (INCL REDIR)	Bonneville Power Administration	Sierra Pacific Power	SFP
10	Sierra Pacific Power (INCL REDIR)	Avista	PacifiCorp East	NF
11	Sierra Pacific Power (INCL REDIR)	Avista	Sierra Pacific Power	NF
12	Sierra Pacific Power (INCL REDIR)	Avista	Sierra Pacific Power	SFP
13	Sierra Pacific Power (INCL REDIR)	Sierra Pacific Power	PacifiCorp East	NF
14	Sierra Pacific Power (INCL REDIR)	Sierra Pacific Power	PacifiCorp East	NF
15	Sierra Pacific Power (INCL REDIR)	Sierra Pacific Power	PacifiCorp West	NF
16	Sierra Pacific Power (INCL REDIR)	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
17	Sierra Pacific Power (INCL REDIR)	Sierra Pacific Power	Bonneville Power Administration	NF
18	Sierra Pacific Power (INCL REDIR)	PacifiCorp East	PacifiCorp East	NF
19	Sierra Pacific Power (INCL REDIR)	PacifiCorp East	PacifiCorp East	NF
20	Sierra Pacific Power (INCL REDIR)	Idaho Power Company	Idaho Power Company	NF
21	Sierra Pacific Power			AD
22	TransAlta Energy Marketing	PacifiCorp East	Bonneville Power Administration	NF
23	TransAlta Energy Marketing	PacifiCorp East	PacifiCorp East	NF
24	Utah Associated Municipal Power Systems	PacifiCorp East	Sierra Pacific Power	NF
25	Utah Associated Municipal Power Systems	PacifiCorp East	Sierra Pacific Power	NF
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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.
5	JBSN	BRDY		150	150	1
5	JBSN	IPCO		36	36	2
5	JBSN	LGBP		200	200	3
5	JBSN	M345		47,354	47,354	4
5	JEFF	BOBR		146	146	5
5	JEFF	M345		129,276	129,276	6
5	LGBP	BOBR		920	920	7
5	LGBP	M345		54,167	54,167	8
5	LGBP	M345		475	475	9
5	LOLO	BOBR		992	992	10
5	LOLO	M345		58,075	58,075	11
5	LOLO	M345		28,832	28,832	12
5	M345	BOBR		641	641	13
5	M345	BRDY		60	60	14
5	M345	JBSN		497	497	15
5	M345	JEFF		874	874	16
5	M345	LGBP		14,700	14,700	17
5	MLCK	BOBR		39,546	39,546	18
5	MLCK	BRDY		1,884	1,884	19
5	OBBLPR	IPCO		128	128	20
5						21
5	BORA	LGBP		122	122	22
5	MLCK	BOBR		100	100	23
5	BOBR	M345		2,650	2,650	24
5	BORA	M345		3,984	3,984	25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			0	**5,036,540**	**5,036,540**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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.
1,419,857	-275,411		1,144,446	1
-17,193			-17,193	2
1,177,728	-134,236		1,043,492	3
-8,537			-8,537	4
627,795	13,886		641,681	5
-9,022			-9,022	6
2,569,661	79,793		2,649,454	7
-32,678			-32,678	8
	14,978		14,978	9
	-57,845		-57,845	10
	150,297		150,297	11
6,589	1,407		7,996	12
-87			-87	13
54,602			54,602	14
	7,984		7,984	15
	17,969		17,969	16
	2,860		2,860	17
	2,730		2,730	18
	12,100		12,100	19
	2,904		2,904	20
	13,964		13,964	21
	-2,016		-2,016	22
	87		87	23
	58,990		58,990	24
	141,825		141,825	25
	59,559		59,559	26
	20,497		20,497	27
	34,182		34,182	28
	73		73	29
	47,551		47,551	30
	3,714		3,714	31
	70		70	32
	2,613		2,613	33
				34
5,788,715	**12,534,575**	**0**	**18,323,290**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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.
	557		557	1
	638		638	2
	493		493	3
	403,936		403,936	4
	2,759		2,759	5
	177,244		177,244	6
	145		145	7
	12,757		12,757	8
	307		307	9
	380		380	10
	20		20	11
	244		244	12
	23,989		23,989	13
	18,220		18,220	14
	104		104	15
	5,329		5,329	16
	255		255	17
	3,841		3,841	18
	29,875		29,875	19
	24,044		24,044	20
	13,089		13,089	21
	566		566	22
	2,323		2,323	23
	71,298		71,298	24
	42,910		42,910	25
	212,160		212,160	26
	3,583		3,583	27
	493		493	28
	1,642		1,642	29
	7,356		7,356	30
	2,019		2,019	31
	44,225		44,225	32
	435		435	33
				34
5,788,715	**12,534,575**	**0**	**18,323,290**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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.
	195,346		195,346	1
	217,897		217,897	2
	64		64	3
	122		122	4
	189		189	5
	885		885	6
	1,796		1,796	7
	17		17	8
	2,970		2,970	9
	-23,567		-23,567	10
	42,622		42,622	11
	3,559		3,559	12
	3,025		3,025	13
	126,872		126,872	14
	41,223		41,223	15
	241		241	16
	1,206		1,206	17
	1,206		1,206	18
	2,606		2,606	19
	90,343		90,343	20
	157		157	21
	274		274	22
	126		126	23
	15,108		15,108	24
	2,961		2,961	25
	283		283	26
	929		929	27
	2,526		2,526	28
	731		731	29
	83,423		83,423	30
	4,214		4,214	31
	1,505		1,505	32
	2,772		2,772	33
				34
5,788,715	**12,534,575**	**0**	**18,323,290**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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.
	32,131		32,131	1
	205		205	2
	2,022		2,022	3
	2,309		2,309	4
	14,529		14,529	5
	211		211	6
	23,911		23,911	7
	-572		-572	8
	114		114	9
	496		496	10
	486		486	11
	97		97	12
	9,257		9,257	13
	20,349		20,349	14
	3,847		3,847	15
	405		405	16
	691		691	17
	2,577		2,577	18
	161		161	19
	12,100		12,100	20
	2,955		2,955	21
	3,551		3,551	22
	987		987	23
	691		691	24
	1,234		1,234	25
	1,876		1,876	26
	296		296	27
	29,214		29,214	28
	7,838		7,838	29
	3,297		3,297	30
	9,832		9,832	31
	1,366		1,366	32
	1,408		1,408	33
				34
5,788,715	**12,534,575**	**0**	**18,323,290**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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.
	388		388	1
	138		138	2
	902		902	3
	2,491		2,491	4
	18,296		18,296	5
	-669		-669	6
	1,029		1,029	7
	727		727	8
	178,524		178,524	9
	5,132		5,132	10
	267,683		267,683	11
	47,432		47,432	12
	607		607	13
	28,953		28,953	14
	126,631		126,631	15
	3,742		3,742	16
	4,063		4,063	17
	8,831		8,831	18
	252		252	19
	224,523		224,523	20
	45,901		45,901	21
	20,891		20,891	22
	327,487		327,487	23
	51,568		51,568	24
	495,820		495,820	25
	136,818		136,818	26
	1,138,751		1,138,751	27
	4,110		4,110	28
	-37,679		-37,679	29
	985		985	30
	1,496		1,496	31
	333		333	32
	26,106		26,106	33
				34
5,788,715	12,534,575	0	18,323,290	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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.
	94		94	1
	1,787		1,787	2
	24,552		24,552	3
	-788		-788	4
	513		513	5
	1,967		1,967	6
	1,276		1,276	7
	183,755		183,755	8
	420		420	9
	174,051		174,051	10
	8,195		8,195	11
	7,496		7,496	12
	280,449		280,449	13
	5,088		5,088	14
	13,448		13,448	15
	4,278		4,278	16
	64		64	17
	19,803		19,803	18
	22,326		22,326	19
	1,090		1,090	20
	382,934		382,934	21
	55,077		55,077	22
	82,080		82,080	23
	15,030		15,030	24
	70,811		70,811	25
	746		746	26
	11,074		11,074	27
	258,797		258,797	28
	118,443		118,443	29
	2,044		2,044	30
	11,108		11,108	31
	129,072		129,072	32
	15,216		15,216	33
				34
5,788,715	**12,534,575**	**0**	**18,323,290**	

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.
	3,218		3,218	1
	9,336		9,336	2
	51		51	3
	238,078		238,078	4
	924		924	5
	15,572		15,572	6
	1,908		1,908	7
	1,539		1,539	8
	41,417		41,417	9
	348		348	10
	551		551	11
	10,777		10,777	12
	958		958	13
	123		123	14
	2,573		2,573	15
	6,868		6,868	16
	827		827	17
	9,963		9,963	18
	43,350		43,350	19
	1,018		1,018	20
	91,216		91,216	21
	195		195	22
	16,268		16,268	23
	87,193		87,193	24
	34,748		34,748	25
	4,206		4,206	26
	23,568		23,568	27
	8,543		8,543	28
	127		127	29
	729		729	30
	479		479	31
	116,972		116,972	32
	22,699		22,699	33
				34
5,788,715	**12,534,575**	**0**	**18,323,290**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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.
	543		543	1
	85		85	2
	204		204	3
	4,884		4,884	4
	59		59	5
	49,786		49,786	6
	46,751		46,751	7
	25,684		25,684	8
	-31,619		-31,619	9
	2,569		2,569	10
	282		282	11
	852		852	12
	5		5	13
	348		348	14
	301		301	15
	27,984		27,984	16
	1,960		1,960	17
	20,985		20,985	18
	37,905		37,905	19
	-646		-646	20
	9,443		9,443	21
	2,478		2,478	22
	297		297	23
	4,216		4,216	24
	371		371	25
	-97		-97	26
	5,346		5,346	27
	2,253		2,253	28
	66,588		66,588	29
	-4,147		-4,147	30
	9,225		9,225	31
	115,392		115,392	32
	4,845		4,845	33
				34
5,788,715	**12,534,575**	**0**	**18,323,290**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/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.
	38,413		38,413	1
	12,972		12,972	2
	12,638		12,638	3
	2,287		2,287	4
	183		183	5
	461		461	6
	2,533		2,533	7
	957		957	8
	2,998		2,998	9
	88		88	10
	2,009		2,009	11
	20,227		20,227	12
	57,050		57,050	13
	88		88	14
	88,103		88,103	15
	152,686		152,686	16
	3,680		3,680	17
	844		844	18
	1,407		1,407	19
	1,879,637		1,879,637	20
	97,457		97,457	21
	146		146	22
	-3,602		-3,602	23
	78		78	24
	31,245		31,245	25
	152,883		152,883	26
	6,841		6,841	27
	36,628		36,628	28
	16,170		16,170	29
	4,873		4,873	30
	150,610		150,610	31
	6,561		6,561	32
	1,866		1,866	33
				34
5,788,715	**12,534,575**	**0**	**18,323,290**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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.
	466		466	1
	112		112	2
	622		622	3
	147,252		147,252	4
	454		454	5
	401,997		401,997	6
	2,861		2,861	7
	168,438		168,438	8
	1,477		1,477	9
	3,085		3,085	10
	180,590		180,590	11
	89,659		89,659	12
	1,993		1,993	13
	187		187	14
	1,545		1,545	15
	2,718		2,718	16
	45,711		45,711	17
	122,973		122,973	18
	5,858		5,858	19
	398		398	20
	-24,824		-24,824	21
	307		307	22
	251		251	23
	8,841		8,841	24
	13,292		13,292	25
				26
				27
				28
				29
				30
				31
				32
				33
				34
5,788,715	**12,534,575**	**0**	**18,323,290**	

Schedule Page: 328 Line No.: 1 Column: e
5, Open Access Transmission Tariff, Volume 5, first revision

Schedule Page: 328 Line No.: 1 Column: h
The network service agreement between Idaho Power and the Bonneville Power Administration for the Oregon Trail Electric Cooperative expires September 30, 2011.

Schedule Page: 328 Line No.: 2 Column: h
OATT rate adjustments filed for periods prior to 2008

Schedule Page: 328 Line No.: 3 Column: h
The network service agreement between Idaho Power and the Bonneville Power Administration for the USBR expires December 31, 2014.
The billing demand for network service is the customer's demand at the time of Idaho Power Company transmission system peak and varies by month.

Schedule Page: 328 Line No.: 4 Column: h
OATT rate adjustments filed for periods prior to 2008

Schedule Page: 328 Line No.: 5 Column: h
The network service agreement between Idaho Power and the Bonneville Power Administration for Raft River expires September 30, 2011.
The billing demand for network service is the customer's demand at the time of Idaho Power Company transmission system peak and varies by month.

Schedule Page: 328 Line No.: 6 Column: h
OATT rate adjustments filed for periods prior to 2008

Schedule Page: 328 Line No.: 7 Column: h
The network service agreement between Idaho Power and the Bonneville Power Administration for the Priority Firm Customers expires December 31, 2011. The billing demand for network service is the customer's demand at the time of Idaho Power Company transmission system peak and varies by month.

Schedule Page: 328 Line No.: 8 Column: h
OATT rate adjustments filed for periods prior to 2008

Schedule Page: 328 Line No.: 9 Column: e
Legacy, contract prior to the Open Access Transmission Tariff

Schedule Page: 328 Line No.: 9 Column: h
The contract between Idaho Power and the Milner Irrigation District expires December 31, 2012.

Schedule Page: 328 Line No.: 10 Column: h
The agreement between Idaho Power and the City of Seattle expires December 31, 2017. Beginning May 1, 2008, Cargill is responsible for the payment of Lucky Peak imbalance.

Schedule Page: 328 Line No.: 11 Column: h
The agreement between Idaho Power and the City of Seattle expires December 31, 2017. Beginning May 1, 2008, Cargill is responsible for the payment of Lucky Peak imbalance.

Schedule Page: 328 Line No.: 12 Column: h
The contract between Idaho Power and PacifiCorp - Imnaha expires on September 30, 2010.

Schedule Page: 328 Line No.: 13 Column: h
OATT rate adjustments filed for periods prior to 2008

Schedule Page: 328 Line No.: 14 Column: e
Legacy, contract prior to the Open Access Transmission Tariff

Schedule Page: 328 Line No.: 14 Column: h
The agreement between Idaho Power and the United States Department of the Interior, Bureau of Indian Affairs is subject to termination upon 90 days written notice by the Bureau.

Schedule Page: 328 Line No.: 15 Column: e
Legacy, contract prior to the Open Access Transmission Tariff

Schedule Page: 328 Line No.: 15 Column: h
The contract between Idaho Power and PacifiCorp is for the life of Bridger project per 1992 Restated Transmission Service Agreement (RTSA) FERC filing 3/9/92.

Schedule Page: 328 Line No.: 22 Column: h
OATT rate adjustments filed for periods prior to 2008

Schedule Page: 328.2 Line No.: 10 Column: h
OATT rate adjustments filed for periods prior to 2008

Schedule Page: 328.3 Line No.: 8 Column: h
OATT rate adjustments filed for periods prior to 2008

Schedule Page: 328.4 Line No.: 6 Column: h
OATT rate adjustments filed for periods prior to 2008

Schedule Page: 328.4 Line No.: 29 Column: h

OATT rate adjustments filed for periods prior to 2008

Schedule Page: 328.5 Line No.: 4 Column: h

OATT rate adjustments filed for periods prior to 2008

Schedule Page: 328.7 Line No.: 9 Column: h

OATT rate adjustments filed for periods prior to 2008

Schedule Page: 328.7 Line No.: 20 Column: h

OATT rate adjustments filed for periods prior to 2008

Schedule Page: 328.7 Line No.: 26 Column: h

OATT rate adjustments filed for periods prior to 2008

Schedule Page: 328.7 Line No.: 30 Column: h

OATT rate adjustments filed for periods prior to 2008

Schedule Page: 328.8 Line No.: 23 Column: h

OATT rate adjustments filed for periods prior to 2008

Schedule Page: 328.9 Line No.: 21 Column: h

OATT rate adjustments filed for periods prior to 2008

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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	Avista Corp - WWp Div	NF	105,567	105,567		547,988		547,988
2	Avista Corp - WWP Div	SFP	250,347	250,347		890,771		890,771
3	Bonneville Power Admin	LFP	469,247	469,247	1,195,541			1,195,541
4	Bonneville Power Admin	LFP			53,856			53,856
5	Bonneville Power Admin	NF	13,366	13,366		72,485		72,485
6	Bonneville Power Admin	SFP	339,360	339,360		1,568,238		1,568,238
7	Bonneville Power Admin	OS					-7,788	-7,788
8	Bonneville Power Admin	OS					5,000	5,000
9	Bonneville Power Admin	OS					3,279	3,279
10	Calpine Energy Serv L.P	OS					-391	-391
11	Eugene Water & Electr	OS					-5,572	-5,572
12	JP Morgan Ventures Engr	SFP	16,200	16,200		30,816		30,816
13	Northwestern Energy	NF	7,488	7,488		38,350		38,350
14	NorthWesern Energy	SFP	83,337	83,337		696,214		696,214
15	NorthWestern Energy	LFP	112,770	112,770	212,800	86,509		299,309
16	NorthWestern Energy	OS					-85,920	-85,920
	TOTAL		1,629,307	1,629,307	1,462,197	6,004,472	-216,370	7,250,299

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	PacifiCorp Inc.	NF	31,360	31,360		198,556		198,556
2	PacifiCorp Inc.	SFP	107,761	107,761		911,250		911,250
3	PacifiCorp Inc.	LFP	46,762	46,762		746,847		746,847
4	PacifiCorp Inc.	OS					-2,605	-2,605
5	PacifiCorp Inc.	OS					3,137	3,137
6	Powerex Corp.	OS					-27,375	-27,375
7	Seattle City Light	NF	3,204	3,204		10,330		10,330
8	Seattle City Light	SFP	17,150	17,150		84,772		84,772
9	Sierra Pacific Power Co	NF	13,534	13,534		96,091		96,091
10	Sierra Pacific Power Co	SFP	3,600	3,600		7,200		7,200
11	Snohomish County PUD	NF	2,400	2,400		5,400		5,400
12	Snohomish County PUD	SFP	4,704	4,704		8,817		8,817
13	Tacoma Power	NF	1,150	1,150		3,838		3,838
14	TransAlta Energy Markt	OS					-98,135	-98,135
15								
16								
	TOTAL		1,629,307	1,629,307	1,462,197	6,004,472	-216,370	7,250,299

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Schedule Page: 332 Line No.: 3 Column: b
Contract Expires 9/30/2016

Schedule Page: 332 Line No.: 4 Column: b
Contract Expires 7/16/2011

Schedule Page: 332 Line No.: 7 Column: g
Unauthorized Increase Charge

Schedule Page: 332 Line No.: 8 Column: g
Processing Fee

Schedule Page: 332 Line No.: 9 Column: g
Transmission Study Fee

Schedule Page: 332 Line No.: 10 Column: g
Resale Transmission

Schedule Page: 332 Line No.: 11 Column: g
Resale Transmission

Schedule Page: 332 Line No.: 15 Column: b
Contract can be terminated at anytime, with 30 days prior notice

Schedule Page: 332 Line No.: 16 Column: g
Rate Refund

Schedule Page: 332.1 Line No.: 3 Column: b
Contract Expires 6/01/2009

Schedule Page: 332.1 Line No.: 4 Column: g
Unauthorized Increase Charge

Schedule Page: 332.1 Line No.: 5 Column: g
Transmission Study Fee

Schedule Page: 332.1 Line No.: 6 Column: g
Resale Transmission

Schedule Page: 332.1 Line No.: 14 Column: g
Resale Transmission

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	369,096
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	172,168
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	1,359,916
6	Richard Dahl	17,200
7	Christine King	45,591
8	Jon Miller	100,800
9	Gary Michael	69,600
10	Richard Reiten	47,052
11	Joan Smith	61,648
12	Jan Packwood	42,000
13	Judith Johansen	51,600
14	Peter O'Neill	63,360
15	Thomas Wilford	52,800
16	Robert Tintsman	66,181
17		
18	Chambers of Commerce & Other Civic Organizations	99,006
19	Associated Taxpayers of Idaho	21,252
20	Corporate Executive Board	42,814
21	Eastern Oregon Visitor Association	1,500
22	Idaho Association of Counties	1,255
23	Idaho Association of Commerce & Industry	10,000
24	Idaho Economic Development Association	1,000
25	Idaho Mining Assocaition	6,960
26	Misc Memberships (3)	1,300
27	National Assoc of Corp	4,500
28	National HydroPower Assoc	28,805
29	Pacific NW Utilities	35,810
30	The Conference Board	3,200
31	University of Idaho	10,950
32	Utility Wind Interest Group	5,000
33	West Associates	22,580
34	Western Energy Institute	40,599
35	Western Electricity Coordiniating Council	598,809
36	Wyoming Taxpayers Assoc	1,500
37		
38	Misc General Management:	
39	New York Stock Exchange	45,567
40	PR Newswire	13,991
41		
42		
43		
44		
45		
46	TOTAL	3,515,410

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

Recipient	Purpose	Amount
Ambac Assurance Corp	Annual Prem	$ 98,810
Bank of New York	Port Morrow-PC	10,854
Broadridge Finc Solution	Proxy & Bulletin	58,158
Deutche Bank	Broker Fees	133,105
E Source	Membership	30,536
Jet Clearing	Travel Expense	19,627
JP Morgan	Am Falls- PRT	30,860
Global Insight	Data Subscription	25,027
Laurel Hill Advsiory	Proxy Printer	80,160
Port of Morrow	Port of Morrow bond	5,475
Shareholder.Com	Shareholder Webcasting	16,989
Stock Based Comp	Stock expnese	442,757
Original Issue Shares	Mgmt Expense	14,400
Thompson Financial	Analyst Service	68,404
Union Bank of Calif	PC Bond exp	13,927
Wells Fargo	Transfer & Fees	128,342
Misc entries/Amort	Misc	125,869
Other items under $5,000	Misc	56,616
Total		$1,359,916

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/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			5,482,388		5,482,388
2	Steam Production Plant	20,407,583				20,407,583
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	13,871,109				13,871,109
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	4,350,691				4,350,691
7	Transmission Plant	14,972,859				14,972,859
8	Distribution Plant	30,298,045				30,298,045
9	Regional Transmission and Market Operation					
10	General Plant	13,033,596				13,033,596
11	Common Plant-Electric	-296,300				-296,300
12	TOTAL	96,637,583		5,482,388		102,119,971

B. Basis for Amortization Charges

Account 404

	Balance to be Amortized	2008 Amortization	Balance to be amortized 12/31/08	Remaining months of amortization 12/31/08
(1)	60,000	12,000	48,000	48
(2)	12,803,025	480,872	12,322,343	-
(3)	13,801,327	4,701,329	18,185,632	-
(4)	5,763,749	288,187	5,475,561	228
TOTAL	32,428,100	8,095,753	32,428,100	

(1) Shoshone-Bannock Tribe license and use agreement (termination date December 31, 2023).
(2) Middle snake relicensing costs (amortized over a 30-year license period).
(3) Computer software packages (amortized over a 60 month period from date of purchase).
(4) Shoshone-Bannock Right of Way (termination date December 31, 2028).

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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	310.00	203	75.00		1.98	R4.0	21.80
13	311.00	134,509	100.00	-10.00	2.12	S1.0	23.30
14	312.10	77,220	60.00	-7.00	2.18	R3.0	22.60
15	312.20	455,185	70.00	-5.00	2.38	R1.5	22.30
16	312.30	4,208	25.00	20.00	2.70	R3.0	12.20
17	314.00	132,561	50.00	-10.00	2.78	S0.5	20.30
18	315.00	62,162	65.00	-5.00	1.01	S1.5	22.20
19	316.00	14,533	50.00	-7.00	0.77	R0.5	20.80
20	316.10	59	10.00	-5.00	0.04	L2.5	7.60
21	316.40	226	10.00	25.00	1.53	L2.5	
22	316.50	79	10.00	25.00	0.01	L2.5	8.20
23	316.70	81	19.00	25.00	3.63	S2.0	16.70
24	316.80	1,365	16.00	30.00	7.61	S0.0	9.30
25	317.000	4,362					
26	Subtotal Steam	886,753					
27	331.00	151,277	100.00	-25.00	2.48	R2.5	32.10
28	332.10	19,461	90.00	-20.00	2.07	S4.0	27.20
29	332.20	224,575	90.00	-20.00	2.04	S4.0	29.80
30	332.30	5,472			2.03	SQUARE	28.60
31	333.00	188,275	80.00	-5.00	1.85	R3.0	33.00
32	334.00	41,295	50.00	-5.00	2.91	R1.5	25.30
33	335.00	16,441	90.00		1.97	R2.0	30.50
34	335.10	41	15.00		2.42	SQUARE	12.30
35	335.20	392	20.00		3.53	SQUARE	10.70
36	335.30	629	5.00		13.65	SQUARE	2.00
37	336.00	7,493	75.00		1.91	R3.0	30.40
38	Subtotal Hydro	655,351					
39	341.00	10,422	35.00		3.36	SQUARE	30.40
40	342.00	5,331	35.00		3.10	SQUARE	32.40
41	343.00	91,489	35.00		3.37	SQUARE	29.70
42	344.00	36,238	35.00		2.97	SQUARE	33.80
43	345.00	17,238	35.00		3.11	SQUARE	28.30
44	346.00	3,615	35.00		3.22	SQUARE	29.50
45	Subtotal Other	164,333					
46	350.20	25,291	65.00		1.51	R3.0	54.20
47	350.21	4,363	65.00		1.50	R3.0	63.70
48	352.00	41,274	60.00	-30.00	1.68	R3.0	47.30
49	353.00	286,101	45.00	-5.00	2.06	R1.0	35.40
50	354.00	136,922	65.00	-25.00	1.96	S3.0	48.60

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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	355.00	93,137	55.00	-60.00	2.81	R2.0	36.70
13	356.00	150,453	65.00	-30.00	1.92	R1.5	48.30
14	359.00	318	65.00		0.98	R3.0	23.80
15	Subtotal Transmission	737,859					
16	361.00	24,515	65.00	-30.00	1.85	R2.5	52.60
17	362.00	167,224	50.00	-5.00	189.00	R0.5	42.10
18	364.00	210,586	44.00	-50.00	3.29	R1.5	31.50
19	365.00	116,790	47.00	-40.00	2.95	R0.5	35.10
20	366.00	47,417	60.00	-20.00	1.95	R2.0	51.20
21	367.00	179,510	50.00	-15.00	1.97	S0.5	41.10
22	368.00	381,827	37.00	5.00	1.67	R1.0	30.80
23	369.00	55,557	35.00	-40.00	3.09	R2.5	25.60
24	370.00	53,995	20.00		6.95	O1.0	11.90
25	370.10	4,990	15.00		6.76	S3.0	14.40
26	371.10	56	10.00	-5.00	3.68	S4.0	1.40
27	371.20	2,482	15.00	-5.00	0.63	R2.0	13.90
28	373.00	4,153	25.00	-25.00	4.09	R1.5	13.90
29	374.00	232					
30	Subtotal Distribution	1,249,334					
31	390.11	26,257	100.00	-5.00	2.38	S1.5	33.60
32	390.12	36,065	50.00	-5.00	2.24	L2.0	36.30
33	390.20	9,083	30.00		2.58	S3.0	20.80
34	391.10	14,561	20.00		4.97	SQUARE	10.30
35	391.20	26,653	5.00		24.37	SQUARE	2.10
36	391.21	4,691	7.00		13.96	L4.0	3.90
37	392.10	415	10.00	25.00	6.23	L2.5	5.90
38	392.30	2,580	8.00	50.00	8.62	S2.5	4.30
39	392.40	19,804	10.00	25.00	3.58	L2.5	7.30
40	392.50	567	10.00	25.00	1.49	L2.5	8.60
41	392.60	27,048	19.00	25.00	3.69	S2.0	12.00
42	392.70	4,100	19.00	25.00	2.39	S2.0	11.90
43	392.90	3,918	30.00	25.00	1.99	S1.5	21.10
44	393.00	1,182	25.00		5.40	SQUARE	9.70
45	394.00	4,816	20.00		4.84	SQUARE	11.70
46	395.00	10,712	20.00		5.39	SQUARE	10.20
47	396.00	8,674	16.00	30.00	6.95	S0.0	7.00
48	397.10	6,486	15.00		6.16	SQUARE	7.70
49	397.20	14,906	15.00		6.99	SQUARE	9.60
50	397.30	2,937	15.00		8.36	SQUARE	6.60

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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	397.40	1,782	10.00		8.20	SQUARE	5.60
13	398.00	4,106	15.00		9.57	SQUARE	6.90
14	Subtotal General	231,343					
15	Total Plant	3,924,973					
16							
17							
18							
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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	Annual admin charges assessed by FERC	2,732,698		2,732,698	
3					
4	General Regulatory Expenses and				
5	Various other Dockets		1,550,625	1,550,625	
6					
7	Regulatory Commission Expenses - Idaho				
8	Expenses and various other Dockets		198,618	198,618	
9					
10	Oregon Hydro - Fees Amortization	158,506		158,506	
11					
12	Regulatory Commission Expenses - Oregon				
13	Expenses and various other Dockets		191,750	191,750	
14					
15					
16					
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45					
46	TOTAL	2,891,204	1,940,993	4,832,197	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/Q4

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
Electric	928	2,732,698					2
							3
							4
Electric	928	1,550,625					5
							6
							7
Electric	928	198,618					8
							9
Electric	928	158,506					10
							11
							12
Electric	928	191,750					13
							14
							15
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							45
		4,832,197					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $5,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	A. Electric R, D & D Performed internally:	
2	(1) Generation	Residential
3	e. unconventional generation	Air Conditioning Cool Credit
4		Energy Efficient Lighting
5		Energy House Calls
6		Energy Star Northwest Homes
7		Heating & Cooling Efficiency
8		Home Products
9		Home Weatherization Pilot
10		Insulation retrofit
11		Oregon Residential Weatherization
12		Rebate Advantage
13		WAQC
14		
15		Commercial/Industrial
16		Building Efficiency
17		Easy Upgrades
18		Holiday Lighting
19		Holiday Lighting
20		Custom Efficiency
21		
22		Irrigation
23		Irrigation Efficiency Rewards
24		Irrigation Peak Rewards
25		
26		NEEA
27		Other Programs and Activities
28		DSM Accounting & Analysis
29		Other indirect program expenses
30		
31		
32		
33	Total R, D&D	
34		
35		
36		
37		

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $5,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $5,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
					1
					2
2,969,377			2,969,377		3
1,018,292			1,018,292		4
484,379			484,379		5
302,061			302,061		6
473,551			473,551		7
250,860			250,860		8
52,807			52,807		9
123,454			123,454		10
7,417			7,417		11
90,888			90,888		12
1,419,475			1,419,475		13
					14
					15
1,055,009			1,055,009		16
2,992,261			2,992,261		17
28,782			28,782		18
58			58		19
4,045,671			4,045,671		20
					21
					22
2,103,702			2,103,702		23
1,431,840			1,431,840		24
					25
942,014			942,014		26
421,317			421,317		27
957,904			957,904		28
22,402			22,402		29
					30
					31
					32
21,193,521			21,193,521		33
					34
					35
					36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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	14,027,319		
4	Transmission	5,862,179		
5	Regional Market			
6	Distribution	17,052,975		
7	Customer Accounts	9,686,784		
8	Customer Service and Informational	3,838,198		
9	Sales			
10	Administrative and General	35,507,805		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	85,975,260		
12	Maintenance			
13	Production	6,095,911		
14	Transmission	2,896,439		
15	Regional Market			
16	Distribution	7,901,868		
17	Administrative and General	973,275		
18	TOTAL Maintenance (Total of lines 13 thru 17)	17,867,493		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	20,123,230		
21	Transmission (Enter Total of lines 4 and 14)	8,758,618		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	24,954,843		
24	Customer Accounts (Transcribe from line 7)	9,686,784		
25	Customer Service and Informational (Transcribe from line 8)	3,838,198		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	36,481,080		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	103,842,753		103,842,753
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
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			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
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)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	103,842,753		103,842,753
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	46,570,459		46,570,459
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	46,570,459		46,570,459
72	Plant Removal (By Utility Departments)			
73	Electric Plant			
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)			
77	Other Accounts (Specify, provide details in footnote):			
78	Paid Absences	17,835,747		17,835,747
79	Preliminary Survey & Investigations	338,737		338,737
80	Other Clearing Accounts	2,564,709		2,564,709
81	Stores Expense	4,227,652		4,227,652
82	Other Work in Progress	2,039,481		2,039,481
83	Other Accounts	4,021,412		4,021,412
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	31,027,738		31,027,738
96	TOTAL SALARIES AND WAGES	181,440,950		181,440,950

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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	3,361	23	8	2,213	241	677		230	
2	February	3,133	5	8	1,989	204	677		263	
3	March	2,903	6	8	1,663	179	720		341	
4	Total for Quarter 1	9,397			5,865	624	2,074		834	
5	April	2,832	21	8	1,010	183	785		854	
6	May	3,386	20	15	1,718	284	793		591	
7	June	4,337	30	15	2,781	344	793		419	
8	Total for Quarter 2	10,555			5,509	811	2,371		1,864	
9	July	4,240	3	16	2,887	349	775		229	
10	August	4,042	7	16	2,903	293	771		75	
11	September	2,665	26	11	1,321	199	757		388	
12	Total for Quarter 3	10,947			7,111	841	2,303		692	
13	October	2,898	1	18	1,752	189	702		255	
14	November	2,846	24	8	1,814	243	702		87	
15	December	3,306	17	8	2,168	313	700		125	
16	Total for Quarter 4	9,050			5,734	745	2,104		467	
17	Total Year to Date/Year	39,949			24,219	3,021	8,852		3,857	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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	7,278,844
4	Nuclear	
5	Hydro-Conventional	6,908,211
6	Hydro-Pumped Storage	
7	Other	217,152
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	14,404,207
10	Purchases	3,716,429
11	Power Exchanges:	
12	Received	106,826
13	Delivered	288,567
14	Net Exchanges (Line 12 minus line 13)	-181,741
15	Transmission For Other (Wheeling)	
16	Received	5,042,937
17	Delivered	5,036,540
18	Net Transmission for Other (Line 16 minus line 17)	6,397
19	Transmission By Others Losses	
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	17,945,292

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	14,543,714
23	Requirements Sales for Resale (See instruction 4, page 311.)	57,311
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	1,990,923
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
27	Total Energy Losses	1,353,344
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	17,945,292

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: Idaho Power Company

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	1,555,985	147,250	2,464	24	8AM
30	February	1,292,413	82,137	2,270	5	8AM
31	March	1,439,647	270,922	2,028	3	8AM
32	April	1,240,090	120,346	1,993	1	8AM
33	May	1,516,309	183,831	2,577	19	6PM
34	June	1,661,334	188,126	3,214	30	3PM
35	July	1,891,764	126,428	3,121	3	4PM
36	August	1,782,755	151,934	3,012	7	4PM
37	September	1,475,251	207,119	2,297	18	6PM
38	October	1,279,586	164,444	2,000	1	6PM
39	November	1,226,019	111,665	1,973	24	8AM
40	December	1,584,139	236,721	2,396	17	8AM
41	TOTAL	17,945,292	1,990,923			

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Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Idaho Power Company	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) 04/15/2009	2008/Q4

FOOTNOTE DATA

Schedule Page: 401 Line No.: 16 Column: b

Page 329 column i differs from 401 by 6,397 reported for Lucky Peak variation and BPA Energy Imbalance schedules on page 401. The numbers that are shown on page 328-330 are for 456 wheeling only, but on page 401 they have to be adjusted for 447 transmission.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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: *Jim Bridger* (b)			Plant Name: *Boardman* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Semi-Outdoor Boiler			Conventional		
3	Year Originally Constructed	1974			1980		
4	Year Last Unit was Installed	1979			1980		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	770.50			64.22		
6	Net Peak Demand on Plant - MW (60 minutes)	717			60		
7	Plant Hours Connected to Load	8784			7209		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	5138544000			402636000		
13	Cost of Plant: Land and Land Rights	494358			106610		
14	Structures and Improvements	63859321			13794057		
15	Equipment Costs	418119517			56385936		
16	Asset Retirement Costs	0			0		
17	Total Cost	482473196			70286603		
18	Cost per KW of Installed Capacity (line 17/5) Including	626.1820			1094.4659		
19	Production Expenses: Oper, Supv, & Engr	149839			926650		
20	Fuel	84210935			6023661		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	4170172			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	5836936			272497		
27	Rents	419846			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	52262			2515460		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	8248488			0		
32	Maintenance of Electric Plant	2499711			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	3981568			13876		
34	Total Production Expenses	109569757			9752144		
35	Expenses per Net KWh	0.0213			0.0242		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil		Coal	Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels		Tons	Barrels	
38	Quantity (Units) of Fuel Burned	2870982	14542	0	237858	637	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	9263	140000	0	8346	138800	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	28.599	135.187	0.000	24.118	170.788	0.000
41	Average Cost of Fuel per Unit Burned	28.166	56.726	0.000	23.993	119.861	0.000
42	Average Cost of Fuel Burned per Million BTU	1.515	9.648	0.000	1.430	20.560	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.016	0.000	0.000	0.015	0.000	0.000
44	Average BTU per KWh Net Generation	10404.000	0.000	0.000	9922.000	0.000	0.000

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/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: *Valmy* (d)			Plant Name: *Danskin* (e)			Plant Name: *Bennett Mountain* (f)			Line No.
Steam			Gas Turbine			Gas Turbine			1
Outdoor			Conventional			Conventional			2
1981			2001			2005			3
1985			2001			2005			4
283.50			262.76			172.80			5
375			285			196			6
8554			746			322			7
0			261427			164159			8
0			0			0			9
0			0			0			10
0			8			4			11
1737664000			167976000			49056000			12
769351			402745			0			13
56855766			8954495			1455553			14
273173513			100952129			52070571			15
0			0			0			16
330798630			110309369			53526124			17
1166.8382			419.8104			309.7577			18
573795			146426			42012			19
41780567			12317741			5037853			20
0			0			0			21
3206517			0			0			22
0			0			0			23
0			0			0			24
1817960			204781			189740			25
1628064			261868			111357			26
49853			0			0			27
0			0			0			28
0			0			0			29
398714			99832			57815			30
5956555			85361			86618			31
1801439			423624			85247			32
327487			0			0			33
57540951			13539633			5610642			34
0.0331			0.0806			0.1144			35
Coal	Oil		Gas			Gas			36
Tons	Barrels		MCF			MCF			37
870880	9916	0	1570200	0	0	512253	0	0	38
9802	138778	0	1038	0	0	1038	0	0	39
43.859	139.262	0.000	7.845	0.000	0.000	9.835	0.000	0.000	40
43.107	140.821	0.000	7.845	0.000	0.000	9.835	0.000	0.000	41
2.238	24.160	0.000	7.558	0.000	0.000	9.475	0.000	0.000	42
0.024	0.000	0.000	0.073	0.000	0.000	0.103	0.000	0.000	43
9686.000	0.000	0.000	9703.000	0.000	0.000	10839.000	0.000	0.000	44

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Schedule Page: 402 Line No.: 3 Column: b

This footnote applies to lines 3 and 4. The Jim Bridger Power Plant consists of four equal units constructed jointly by Idaho Power Company and Pacific Power and Light Company, with Idaho owning 1/3 and PacifiCorp owning 2/3. Unit #1 was placed in commercial operation November 30, 1974, Unit #2 December 1, 1975, Unit #3 September 1, 1976, and Unit #4 November 29, 1979.

Schedule Page: 402 Line No.: 3 Column: c

This footnote applies to lines 3 and 4. The Boardman plant consists of one unit constructed jointly by Portland General Electric Company, Idaho Power Company, and Pacific Northwest Generating Company, with Idaho Power Company owning 10%. The unit was placed in commercial operation August 3, 1980.

Schedule Page: 402 Line No.: 3 Column: d

This footnote applies to lines 3 and 4. The Valmy plant consists of two units constructed jointly by Sierra Pacific Power Company and Idaho Power Company, with Sierra owning 1/2 and Idaho owning 1/2. Unit #1 was placed in commercial operation December 11, 1981 and Unit #2 May 21, 1985.

Schedule Page: 402 Line No.: 5 Column: b

This footnote applies to line 5 and lines 12 through 43. Information reflects Idaho Power Company's share as explained in note for line 3 page 402 column B.

Schedule Page: 402 Line No.: 5 Column: c

This footnote applies to line 5 and lines 12 through 43. Information reflects Idaho Power Company's share as explained in note on line 3 page 402 column C

Schedule Page: 402 Line No.: 5 Column: d

This footnote applies to line 5 and lines 12 through 43. Information reflects Idaho Power Company's share as explained in note for line 3 page 403 column D.

Schedule Page: 402 Line No.: 9 Column: b

This footnote applies to lines 9, 10, and 11. PacifiCorp as operator of the plant will report this information.

Schedule Page: 402 Line No.: 9 Column: c

This footnote applies to lines 9, 10, and 11. Portland General Electric Company, as operator will report this information.

Schedule Page: 402 Line No.: 9 Column: d

This footnote applies to lines 9, 10, and 11. Sierra Pacific Power, as operator of the plant, will report this information.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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. 2736 Plant Name: American Falls (b)	FERC Licensed Project No. 1975 Plant Name: Bliss (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Run-of-River
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Outdoor
3	Year Originally Constructed	1978	1949
4	Year Last Unit was Installed	1978	1950
5	Total installed cap (Gen name plate Rating in MW)	92.30	75.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	95	67
7	Plant Hours Connect to Load	5,506	8,784
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	109	76
10	(b) Under the Most Adverse Oper Conditions	0	1
11	Average Number of Employees	4	4
12	Net Generation, Exclusive of Plant Use - Kwh	264,778,000	315,334,000
13	Cost of Plant		
14	Land and Land Rights	875,318	740,154
15	Structures and Improvements	11,807,207	967,473
16	Reservoirs, Dams, and Waterways	4,293,075	8,213,695
17	Equipment Costs	31,399,514	7,277,392
18	Roads, Railroads, and Bridges	839,276	486,477
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	49,214,390	17,685,191
21	Cost per KW of Installed Capacity (line 20 / 5)	533.2003	235.8025
22	Production Expenses		
23	Operation Supervision and Engineering	139,773	724,988
24	Water for Power	2,309,584	433,728
25	Hydraulic Expenses	83,304	469,608
26	Electric Expenses	38,202	54,806
27	Misc Hydraulic Power Generation Expenses	241,429	183,946
28	Rents	156	3,057
29	Maintenance Supervision and Engineering	116,889	101,733
30	Maintenance of Structures	100,254	58,081
31	Maintenance of Reservoirs, Dams, and Waterways	3,785	7,771
32	Maintenance of Electric Plant	279,656	238,805
33	Maintenance of Misc Hydraulic Plant	135,909	108,885
34	Total Production Expenses (total 23 thru 33)	3,448,941	2,385,408
35	Expenses per net KWh	0.0130	0.0076

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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. 1971 Plant Name: Brownlee (d)	FERC Licensed Project No. 2848 Plant Name: Cascade (e)	FERC Licensed Project No. 1971 Plant Name: Oxbow (f)	Line No.
Storage	Run-of-River	Storage	1
Outdoor	Outdoor	Outdoor	2
1958	1983	1961	3
1980	1984	1961	4
585.40	12.42	190.00	5
659	14	218	6
8,782	8,751	8,776	7
			8
747	15	221	9
220	1	202	10
7	2	6	11
2,120,007,000	47,237,000	951,732,000	12
			13
18,069,223	82,142	1,210,187	14
31,245,788	7,364,154	9,956,831	15
66,787,436	3,145,630	30,375,714	16
52,577,131	12,729,814	15,788,644	17
518,444	122,668	565,842	18
0	0	0	19
169,198,022	23,444,408	57,897,218	20
289.0298	1,887.6335	304.7222	21
			22
750,163	172,275	372,539	23
448,065	105,669	205,834	24
760,847	177,126	363,156	25
331,519	82,474	191,076	26
537,499	136,528	243,686	27
237,758	113	40,826	28
435,098	69,737	200,140	29
255,345	42,690	290,134	30
280,498	3,317	9,028	31
396,062	128,839	186,019	32
723,775	87,519	404,437	33
5,156,629	1,006,287	2,506,875	34
0.0024	0.0213	0.0026	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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. 1971 Plant Name: Hells Canyon (b)	FERC Licensed Project No. 2726 Plant Name: Malad (c)
1	Kind of Plant (Run-of-River or Storage)	Storage	Run-of-River
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Outdoor
3	Year Originally Constructed	1967	1948
4	Year Last Unit was Installed	1967	1948
5	Total installed cap (Gen name plate Rating in MW)	391.50	21.77
6	Net Peak Demand on Plant-Megawatts (60 minutes)	441	26
7	Plant Hours Connect to Load	8,784	8,784
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	445	25
10	(b) Under the Most Adverse Oper Conditions	137	21
11	Average Number of Employees	5	1
12	Net Generation, Exclusive of Plant Use - Kwh	1,885,251,000	158,613,000
13	Cost of Plant		
14	Land and Land Rights	1,865,984	205,376
15	Structures and Improvements	2,413,190	2,671,314
16	Reservoirs, Dams, and Waterways	52,700,383	6,219,827
17	Equipment Costs	15,231,708	4,091,287
18	Roads, Railroads, and Bridges	819,192	304,683
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	73,030,457	13,492,487
21	Cost per KW of Installed Capacity (line 20 / 5)	186.5401	619.7743
22	Production Expenses		
23	Operation Supervision and Engineering	347,537	134,202
24	Water for Power	201,877	583,708
25	Hydraulic Expenses	350,702	158,683
26	Electric Expenses	146,405	57,328
27	Misc Hydraulic Power Generation Expenses	251,693	78,084
28	Rents	68,206	0
29	Maintenance Supervision and Engineering	237,745	46,887
30	Maintenance of Structures	49,940	12,000
31	Maintenance of Reservoirs, Dams, and Waterways	16,160	26,115
32	Maintenance of Electric Plant	276,698	32,814
33	Maintenance of Misc Hydraulic Plant	603,525	88,090
34	Total Production Expenses (total 23 thru 33)	2,550,488	1,217,911
35	Expenses per net KWh	0.0014	0.0077

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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. 2055 Plant Name: C J Strike (d)	FERC Licensed Project No. 503 Plant Name: Swan Falls (e)	FERC Licensed Project No. 18 Plant Name: Twin Falls (f)	Line No.
Run-of-River	Run-of-River	Run-of-River	1
Outdoor	Conventional	Conventional	2
1952	1910	1935	3
1952	1994	1995	4
82.80	25.00	52.74	5
84	20	30	6
8,762	8,768	8,784	7
			8
91	24	53	9
84	14	50	10
7	4	5	11
386,403,000	114,955,000	74,045,000	12
			13
3,353,651	51,675	255,499	14
6,049,184	25,357,052	10,823,950	15
10,201,230	13,856,887	7,908,870	16
7,460,833	30,378,323	20,598,630	17
248,183	835,946	1,917,603	18
0	0	0	19
27,313,081	70,479,883	41,504,552	20
329.8681	2,819.1953	786.9653	21
			22
1,015,212	252,191	201,677	23
757,997	162,357	132,692	24
1,318,885	181,279	110,028	25
33,863	28,083	36,660	26
391,877	131,425	146,334	27
69,656	8,074	1,131	28
260,710	92,665	17,834	29
164,018	119,589	9,598	30
228,392	59,632	2,489	31
569,022	86,032	28,543	32
271,564	119,377	53,012	33
5,081,196	1,240,704	739,998	34
0.0132	0.0108	0.0100	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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. 2777 Plant Name: Upper Salmon (b)	FERC Licensed Project No. 2778 Plant Name: Shoshone Falls (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Run-of-River
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional
3	Year Originally Constructed	1937	1907
4	Year Last Unit was Installed	1947	1921
5	Total installed cap (Gen name plate Rating in MW)	34.50	12.50
6	Net Peak Demand on Plant-Megawatts (60 minutes)	36	13
7	Plant Hours Connect to Load	8,784	4,206
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	39	14
10	(b) Under the Most Adverse Oper Conditions	32	11
11	Average Number of Employees	4	2
12	Net Generation, Exclusive of Plant Use - Kwh	210,736,000	47,665,000
13	Cost of Plant		
14	Land and Land Rights	200,112	311,407
15	Structures and Improvements	1,834,850	1,212,177
16	Reservoirs, Dams, and Waterways	4,960,389	512,402
17	Equipment Costs	6,637,152	4,589,586
18	Roads, Railroads, and Bridges	29,359	51,383
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	13,661,862	6,676,955
21	Cost per KW of Installed Capacity (line 20 / 5)	395.9960	534.1564
22	Production Expenses		
23	Operation Supervision and Engineering	406,588	254,415
24	Water for Power	184,357	177,585
25	Hydraulic Expenses	333,729	254,108
26	Electric Expenses	24,606	21,816
27	Misc Hydraulic Power Generation Expenses	160,667	131,944
28	Rents	0	30
29	Maintenance Supervision and Engineering	92,052	99,967
30	Maintenance of Structures	71,669	28,922
31	Maintenance of Reservoirs, Dams, and Waterways	63,154	40,933
32	Maintenance of Electric Plant	74,886	56,241
33	Maintenance of Misc Hydraulic Plant	125,669	73,255
34	Total Production Expenses (total 23 thru 33)	1,537,377	1,139,216
35	Expenses per net KWh	0.0073	0.0239

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. 1971 Plant Name: Common Facilities (d)	FERC Licensed Project No. 2061 Plant Name: Lower Salmon (e)	FERC Licensed Project No. 2899 Plant Name: Milner (f)	Line No.
	Run-of-River	Run-of-River	1
	Outdoor	Conventional	2
	1949	1992	3
	1949	1992	4
0.00	60.00	59.45	5
0	50	24	6
0	8,784	7,248	7
			8
0	64	61	9
0	60	1	10
0	7	1	11
0	210,394,000	52,546,000	12
			13
114,367	422,168	138,100	14
25,988,200	2,728,103	10,336,682	15
13,556,785	6,960,182	17,147,050	16
1,253,321	6,941,771	27,640,547	17
99,051	88,693	501,877	18
0	0	0	19
41,011,724	17,140,917	55,764,256	20
0.0000	285.6820	938.0026	21
			22
0	762,677	78,026	23
0	279,859	1,376,313	24
4,964,233	354,852	39,769	25
0	143,579	35,923	26
138,233	190,367	117,086	27
0	1,321	1,565	28
0	51,138	41,659	29
0	114,790	19,783	30
0	4,208	32,438	31
0	33,590	65,665	32
100,144	108,944	75,851	33
5,202,610	2,045,325	1,884,078	34
0.0000	0.0097	0.0359	35

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Name of Respondent Idaho Power Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report 2008/Q4

FOOTNOTE DATA

Schedule Page: 406 Line No.: 1 Column: b

American Falls generating capacity is dependent upon water releases controlled by the United States Bureau of Reclamation.

Schedule Page: 406 Line No.: 1 Column: e

Cascade generating capacity is dependent upon water releases controlled by the United States Bureau of Reclamation.

Schedule Page: 406 Line No.: 1 Column: f

Upstream storage in Brownlee Reservoir.

Schedule Page: 406.1 Line No.: 1 Column: b

Upstream storage in Brownlee Reservoir

Schedule Page: 406.1 Line No.: 1 Column: c

Lower Malad maximum demand 15,000 Kw, Upper Malad maximum demand 9,000 Kw non-coincident.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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	Hydro:					
2	Clear Lakes	1937	2.50	2.2	16,198	1,759,032
3	Thousand Springs	1912	8.80	7.0	52,227	4,730,494
4						
5						
6	Internal Combustion:					
7	Salmon Diesel (1)	1967	5.00	5.0	120	901,055
8						
9						
10						
11	(1) Salmon units are classified as standby.					
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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
703,613	100,971		104,993			2
537,556	40,665		69,995			3
						4
						5
						6
180,211				Diesel		7
						8
						9
						10
						11
						12
						13
						14
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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 From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate 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)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Boardman	Slatt	500.00	500.00	S Tower	1.79		1
2								
3	Borah	Midpoint	345.00	500.00	S Tower	84.97		1
4	Jim Bridger	Goshen	345.00	345.00	S Tower	226.17		1
5	State Line	Midpoint	345.00	345.00	S Tower	76.08		2
6	Kinport	Borah	345.00	345.00	S Tower	27.26		1
7	Midpoint	Borah #1	345.00	345.00	H Wood	79.28		1
8	Midpoint	Borah #2	345.00	345.00	H Wood	77.59		2
9	Adelaide Tap	Adelaide	345.00	345.00	H Wood	2.67		2
10								
11	Quartz	LaGrande	230.00	230.00	H Wood	46.23		1
12	Midpoint	Hunt	230.00	230.00	S Tower	0.53		2
13	Brady	Antelope	230.00	230.00	H Wood	56.29		1
14	Brady	Treasureton	230.00	230.00	H Wood	0.13		1
15	Brady #1 & #2	Kinport	230.00	230.00	S Tower	17.94		2
16	Jim Bridger	Point of Rocks	230.00	230.00	H Wood	1.40		1
17	Brownlee	Ontario	230.00	230.00	S Tower	72.70		1
18	Mora	Bowmont	138.00	230.00	S P Wood	9.90		1
19	Mora	Bowmont	138.00	230.00	H Wood	10.77		1
20	Jim Bridger	Point of Rocks	230.00	230.00	H Wood	2.79		1
21	Caldwell 710	Locust	230.00	230.00	SP Steel	18.60		1
22	Boise Bench	Caldwell	230.00	230.00	S Tower	7.58		1
23	Boise Bench	Caldwell	230.00	230.00	H Wood	33.53		1
24	Boise Bench	Cloverdale	230.00	230.00	S Tower	15.98		2
25	Boardman	Dalreed Sub	230.00	230.00	H Wood	1.68		1
26	Brownlee 714	Oxbow	230.00	230.00	SP Steel	11.13		2
27	Caldwell	Ontario	230.00	230.00	H Wood	27.11		1
28	Caldwell	Ontario	230.00	230.00	S Tower	3.28		1
29	Bennett Mtn PP	Rattlesnake TS	230.00	230.00	SP Steel	4.48		1
30	Borah	Hunt	230.00	230.00	H Steel	68.23		1
31	Danskin	Hubbard	230.00	230.00	H Steel	36.24		1
32	Danskin	Hubbard	230.00	230.00	SP Steel	1.90		1
33	Danskin	Hubbard	230.00	230.00	SP Steel	1.30		2
34	Danskin	Bennett Mtn	230.00	230.00	SP Steel	2.30		1
35	Boise Bench	Midpoint #1	230.00	230.00	S Tower	0.86		1
36					TOTAL	4,726.77	11.02	173

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
2X1780 ACSR		446,708	446,708					1
								2
1272 ACSR	256,381	21,776,998	22,033,379					3
1272 ACSR	483,309	15,888,761	16,372,070		15,882,152	16,365,461	32,247,613	4
795 ACSR	571,979	10,996,449	11,568,428					5
1272 ACSR	344,220	6,028,033	6,372,253					6
715.5 ACSR	283,143	5,779,608	6,062,751		5,763,958	6,047,101	11,811,059	7
715.5 ACSR	64,851	7,786,556	7,851,407		7,684,278	7,749,129	15,433,407	8
715.5 ACSR	51,448	347,946	399,394					9
								10
795 ACSR	51,414	2,411,863	2,463,277		2,494,190	2,545,604	5,039,794	11
715.5 ACSR	9,145	998,452	1,007,597					12
1272 ACSR	108,301	2,502,500	2,610,801					13
795 ACSR		6,186	6,186					14
715.5 ACSR	18,829	969,476	988,305					15
1272 ACSR	1,190	51,525	52,715					16
2X954 ACSR	1,676,838	20,266,395	21,943,233					17
715.5 ACSR	347,962	2,012,372	2,360,334		2,011,502	2,359,464	4,370,966	18
715.5 ACSR								19
1272 ACSR	1,899	212,523	214,422					20
1590 ACSR	2,138,236	8,755,911	10,894,147					21
1272 ACSR	1,134,421	5,699,649	6,834,070	1,464,007	5,396,300	6,860,307	13,720,614	22
715.5 ACSR								23
1272 ACSR	3,062,812	6,583,109	9,645,921		6,582,253	9,645,065	16,227,318	24
795 AAC		80,895	80,895					25
954 ACSR	34,174	16,026,470	16,060,644					26
2X954 ACSR	194,763	5,925,083	6,119,846		5,890,298	6,085,061	11,975,359	27
1272 ACSR								28
1272 ACSR	81,701	1,666,354	1,748,055					29
1590 ACSR	618,217	22,439,850	23,058,067	624,917	22,468,004	23,092,921	46,185,842	30
1590 Lapwing		9,666,096	9,666,096					31
1590 Lapwing								32
1590 Lapwing								33
1590 Lapwing		3,293,005	3,293,005					34
715.5 ACSR	336,186	3,776,464	4,112,650		4,100,683	4,436,869	8,537,552	35
	28,566,445	369,747,512	398,313,957	6,773,672	199,328,849	227,309,396	433,411,917	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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.
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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	Boise Bench	Midpoint #1	230.00	230.00	H Wood	108.11		1
2	Brownlee	Quartz Jct	230.00	230.00	S Tower	1.52		1
3	Brownlee	Quartz Jct	230.00	230.00	H Wood	41.71		1
4	Brownlee	Boise Bench #1 & #2	230.00	230.00	S Tower	99.97		2
5	Oxbow	Brownlee	230.00	230.00	S Tower	10.23		2
6	Boise Bench	Midpoint #2	230.00	230.00	S Tower	3.42		1
7	Boise Bench	Midpoint #2	230.00	230.00	H Wood	102.53		1
8	Oxbow	Pallette Jct	230.00	230.00	S Tower	20.21		2
9	Pallette Jct	Imnaha	230.00	230.00	H Wood	24.43		2
10	Hells Canyon	Palette Jct	230.00	230.00	S Tower	8.24		2
11	Brownlee	Boise Bench	230.00	230.00	S Tower	102.27		2
12	Boise Bench	Midpoint #3	230.00	230.00	H Wood	106.34		1
13	Palette Jct	Enterprise	230.00	230.00	H Wood	29.08		1
14	Borah	Brady #2	230.00	230.00	S Tower	0.41		1
15	Borah	Brady #2	230.00	230.00	H Wood	3.58		1
16	Borah	Brady #1	230.00	230.00	H Wood	3.83		1
17								
18	Goshen	State Line	161.00	161.00	H Wood	90.49		1
19	Don	Goshen	161.00	161.00	S Tower	2.39		2
20	Don	Goshen	161.00	161.00	H Wood	48.43		2
21								
22	American Falls Power Plant	Adelaide	138.00	138.00	H Wood	9.84		2
23	American Falls Power Plant	Adelaide	138.00	138.00	S P Wood	0.12		2
24	Minidoka Loop	Adelaide	138.00	138.00	S Tower	1.07		2
25	Nampa	Caldwell	138.00	138.00	S P Wood	10.73		2
26	Upper Salmon	Mountain Home Jct	138.00	138.00	H Wood	53.61		1
27	Upper Salmon	Cliff	138.00	138.00	H Wood	30.80		1
28	Eastgate	Russet	138.00	138.00	S P Wood	2.09		1
29	Brady	Fremont	138.00	138.00	S Tower	0.98		2
30	Brady	Fremont	138.00	138.00	H Wood	24.32		2
31	Brady	Fremont	138.00	138.00	S P Wood	24.35		2
32	King	Lower Malad	138.00	138.00	H Wood	84.92		2
33	Emmett Jct	Payette	138.00	138.00	H Wood	66.44		2
34	Mountain Home AFB Tap		138.00	138.00	H Wood	6.20		1
35	Ontario	Quartz	138.00	138.00	H Wood	73.42		1
36					TOTAL	4,726.77	11.02	173

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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)	
715.5 ACSR								1
795 ACSR	53,068	2,011,507	2,064,575					2
795 ACSR								3
VARIOUS	269,431	7,991,043	8,260,474	288,607		8,279,650	8,568,257	4
1272 ACSR	14,810	1,182,550	1,197,360					5
715.5 ACSR	227,825	5,764,129	5,991,954		5,861,700	6,089,525	11,951,225	6
VARIOUS								7
1272 ACSR	23,308	2,075,244	2,098,552					8
1272 ACSR	138,477	1,263,618	1,402,095					9
1272 ACSR	10,737	1,252,130	1,262,867					10
954 ACSR	170,694	5,620,492	5,791,186	184,817		5,805,309	5,990,126	11
715.5 ACSR	247,857	4,954,729	5,202,586		5,416,132	5,663,989	11,080,121	12
1272 ACSR	51,122	1,631,895	1,683,017					13
1272 ACSR	3,068	226,250	229,318		231,992	235,060	467,052	14
715.5 ACSR								15
1272 ACSR	10,064	339,595	349,659		311,349	321,413	632,762	16
								17
250 COPPER	16,155	648,382	664,537					18
715.5 ACSR	76,041	1,652,914	1,728,955					19
397.5 ACSR								20
								21
250 COPPER	26,507	2,388,737	2,415,244		2,397,774	2,424,281	4,822,055	22
250 COPPER								23
715.5 ACSR	15,088	249,232	264,320	21,326	249,233	270,559	541,118	24
795 AAC	157,432	1,954,139	2,111,571		1,753,582	1,911,014	3,664,596	25
795 ACSR	47,687	1,858,259	1,905,946	48,370	2,544,748	2,593,118	5,186,236	26
795 ACSR	43,568	764,183	807,751					27
795 AAC	270,823	557,504	828,327					28
VARIOUS	564,932	3,557,039	4,121,971		3,593,335	4,158,267	7,751,602	29
VARIOUS								30
VARIOUS								31
VARIOUS	76,823	1,622,351	1,699,174		1,797,737	1,874,560	3,672,297	32
VARIOUS	30,918	2,291,614	2,322,532		2,416,389	2,447,307	4,863,696	33
397.5 ACSR	1,955		1,955					34
VARIOUS	34,428	1,552,878	1,587,306		1,551,834	1,586,262	3,138,096	35
	28,566,445	369,747,512	398,313,957	6,773,672	199,328,849	227,309,396	433,411,917	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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	King	American Falls PP	138.00	138.00	S Tower	1.03		2
2	King	American Falls PP	138.00	138.00	H Wood	145.99		1
3	King	American Falls PP	138.00	138.00	S P Wood	3.71		1
4	Duffin	Clawson	138.00	138.00	H Wood	6.22		1
5	American Falls	Brady Tie	138.00	138.00	H Wood	0.33		1
6	Upper Salmon A-B	King	138.00	138.00	H Wood	5.88		1
7	Upper Salmon B	Wells	138.00	138.00	H Wood	125.58		1
8	King	Wood River	138.00	138.00	H Wood	73.56		1
9	Boise Bench	Grove	138.00	138.00	S P Wood	10.44		2
10	Quartz	John Day	138.00	138.00	H Wood	67.31		1
11	Sinker Creek Tap		138.00	138.00	H Wood	2.80		1
12	Mora	Cloverdale	138.00	138.00	H Wood	2.57		1
13	Mora	Cloverdale	138.00	138.00	S P Wood	22.37		1
14	Mora	Cloverdale	138.00	138.00	S P Steel	0.96		2
15	Stoddard Jct	Stoddard Sub	138.00	138.00	S P Steel	3.80		1
16	Fossil Gulch Tap		138.00	138.00	H Wood	1.95		1
17	Wood River	Midpoint	138.00	138.00	H Wood	53.06		2
18	Wood River	Midpoint	138.00	138.00	S P Wood	16.69		2
19	Oxbow	McCall	138.00	138.00	H Wood	38.47		1
20	Oxbow	McCall	138.00	138.00	S P Wood	2.32		1
21	Lowell Jct	Nampa	138.00	138.00	S P Wood	7.57		2
22	Hunt	Milner	138.00	138.00	S P Wood	19.39		1
23	Strike	Bruneau Bridge	138.00	138.00	H Wood	13.48		1
24	American Falls	Kramer Sub	138.00	138.00	S P Wood	18.40		2
25	Pingree	Haven	138.00	138.00	S P Wood	11.75		1
26	Midpoint	Twin Falls	138.00	138.00	S P Wood	25.14		2
27	Twin Falls	Russett	138.00	138.00	S P Wood	1.72		1
28	Blackfoot	Aiken	138.00	138.00	S P Wood	6.17		2
29	Peterson	Tendoy	138.00	138.00	H Wood	57.22		1
30	Eastgate Tap	Eastgate	138.00	138.00	S P Wood	7.30		1
31	Boise Bench	Mora	138.00	138.00	H Wood	13.17		2
32	Bowmont-Caldwell	Simplot Sub	138.00	138.00	S P Wood	0.51		1
33	Gary Lane	Eagle	138.00	138.00	S P Wood	6.53		1
34	Locust Grove	Blackcat Sub	138.00	138.00	S P Steel	9.93	2.98	1
35	Boise Bench	Butler	138.00	138.00	S P Wood	0.08	4.02	1
36					TOTAL	4,726.77	11.02	173

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/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)	
715.5 ACSR	148,914	5,544,203	5,693,117		6,854,888	7,003,802	13,858,690	1
715.5 ACSR								2
715.5 ACSR								3
4\0	4,191	309,827	314,018					4
954 ACSR		96,921	96,921					5
250 COPPER	2,741	93,073	95,814					6
VARIOUS	28,490	1,745,804	1,774,294		2,102,923	2,131,413	4,234,336	7
VARIOUS	173,683	2,355,148	2,528,831		2,691,460	2,865,143	5,556,603	8
VARIOUS	225,602	1,630,589	1,856,191		1,660,128	1,885,730	3,545,858	9
397.5 ACSR	92,173	2,362,416	2,454,589					10
VARIOUS	20	77,199	77,219					11
715.5 ACSR	2,225,226	6,996,618	9,221,844	2,266,792	8,046,783	10,313,575	20,627,150	12
VARIOUS								13
795AAC								14
1272 ACSR								15
250 COPPER	450	63,439	63,889					16
397.5 ACSR	281,064	6,374,306	6,655,370		6,390,048	6,671,112	13,061,160	17
397.5 ACSR								18
397.5 ACSR	109,899	2,314,194	2,424,093		2,417,537	2,527,436	4,944,973	19
397.5 ACSR								20
715.5 ACSR	211,131	1,493,264	1,704,395		1,488,956	1,700,087	3,189,043	21
715.5 ACSR	3,324	1,187,302	1,190,626		1,195,361	1,198,691	2,394,052	22
397.5 ACSR	14,927	587,404	602,331					23
715.5 ACSR	13,734	1,052,549	1,066,283					24
397.5 ACSR	11,213	778,092	789,305	18,223	778,091	796,314	1,592,628	25
VARIOUS	54,848	2,958,765	3,013,613					26
715.5 ACSR	16,790	206,158	222,948					27
715.5 ACSR	13,616	456,919	470,535		477,162	490,778	967,940	28
397.5 ACSR	395,696	3,449,949	3,845,645					29
715.5 ACSR	45,989	1,058,898	1,104,887					30
715.5 ACSR	14,697	627,703	642,400		627,920	642,617	1,270,537	31
795 AAC		49,642	49,642					32
795 AAC	489,037	1,944,888	2,433,925					33
1272 ACSR	935,725	3,610,071	4,545,796					34
1272 ACSR	34,687	838,605	873,292					35
	28,566,445	369,747,512	398,313,957	6,773,672	199,328,849	227,309,396	433,411,917	36

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/Q4

TRANSMISSION LINE STATISTICS

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Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate 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)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Eagle	Star	138.00	138.00	S P Wood	6.35		1
2	Karcher Sub	Zilog Tap	138.00	138.00	S P Steel	2.09		1
3	Cloverdale - 712	712 - Wye	138.00	138.00	S P Steel	0.21	4.02	1
4	Butler	Wye	138.00	138.00	S P Steel	2.85		1
5	Horseflat	Starkey	138.00	138.00	H Wood	33.60		1
6	Starkey	Mccall	138.00	138.00	S P Steel	2.08		2
7	Starkey	Mccall	138.00	138.00	H Wood	3.80		1
8	Starkey	Mccall	138.00	138.00	S P Steel	1.50		1
9	Starkey	Mccall	138.00	138.00	S P Wood	17.61		1
10	Chestnut	Happy Valley	138.00	138.00	S P Steel	2.78		1
11	Garnet	Ward		138.00		5.25		
12	McCall	Lake Fork	138.00	138.00	S P Wood	8.83		1
13	McCall	Lake Fork	138.00	138.00	S Steel	2.90		
14	Caldwell	Willis	138.00	138.00	S P Steel	1.30		1
15	Caldwell	Willis	138.00	138.00	S P Steel	1.59		1
16	Caldwell	Willis	138.00	138.00	S P Wood	0.87		1
17	Valivue Tap		138.00	138.00	S P Steel	0.80		2
18	Kinport	Don #1	138.00	138.00	S Tower	1.24		2
19	Twin Falls PP Tap		138.00	138.00	H Wood	0.82		1
20	American Falls PP	Amercian Falls Trans ST	138.00	138.00	S P Steel	0.37		1
21	Lower Salmon	King Tie	138.00	138.00	H Wood	0.22		1
22	C J Strike	Strike Jct	138.00	138.00	S Tower	4.31		2
23	Strike Jct	Mountain Home Jct	138.00	138.00	H Wood	26.70		1
24	Strike Jct	Bowmont		138.00	H Wood	0.05		1
25	Strike Jct	Bowmont	138.00	138.00	S Tower	0.36		1
26	Strike Jct	Bowmont	138.00	138.00	H Wood	68.22		1
27	Lucky Peak	Lucky Peak Jct	138.00	138.00	H Wood	4.43		2
28	Bliss	King	138.00	138.00	H Wood	10.44		1
29	Milner Deadend	Milner PP	138.00	138.00	S P Wood	1.31		1
30	Swan Falls Tap		138.00	138.00	H Wood	0.95		1
31								
32								
33								
34	Hines	BPA (Harney)	115.00	115.00	H Wood	3.28		1
35								
36					TOTAL	4,726.77	11.02	173

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/Q4

TRANSMISSION LINE STATISTICS (Continued)

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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)	
715.5 ACSR		2,909,433	2,909,433					1
795 AAC	43,035	443,805	486,840					2
1272 ACSR	140,412	709,148	849,560					3
795 ACSR	134,471	1,405,436	1,539,907					4
715.5 ACSR	657,883	19,860,558	20,518,441					5
715.5 ACSR								6
715.5 ACSR								7
715.5 ACSR								8
715.5 ACSR								9
1272 ACSR	78,579	1,821,921	1,900,500					10
	40,580		40,580					11
715.5 ACSR	399,781	4,731,449	5,131,230	331,539	4,662,028	4,993,567	9,987,134	12
								13
1272 ACSR	168,225	2,141,218	2,309,443					14
795 ACSR								15
795 ACSR								16
795 ACSR		351,497	351,497					17
715.5 ACSR	1,174	212,777	213,951					18
250 COPPER	58	53,889	53,947					19
715.5 ACSR		76,560	76,560					20
397.5 ACSR		4,406	4,406					21
715.5 ACSR	1,074	253,872	254,946					22
397.5 ACSR	4,355	524,571	528,926		2,537,731	2,542,086	5,079,817	23
715.5 ACSR	29,902	1,776,898	1,806,800	86,651	1,859,070	1,945,721	3,891,442	24
715.5 ACSR								25
								26
715.5 ACSR	7	279,481	279,488					27
715.5 ACSR	5,620	964,435	970,055					28
715.5 ACSR	2,814	183,606	186,420					29
397.5 ACSR	12,885	261,511	274,396					30
								31
								32
								33
397.5 ACSR	1,978	63,404	65,382					34
								35
	28,566,445	369,747,512	398,313,957	6,773,672	199,328,849	227,309,396	433,411,917	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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								
2	69 Kv Lines		69.00	69.00	H Wood	166.31		1
3	69 Kv Lines		69.00	69.00	S P Wood	923.11		1
4								
5								
6	46 Kv Lines		46.00	46.00	S P Wood	412.07		1
7								
8								
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					TOTAL	4,726.77	11.02	173

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
								1
VARIOUS	928,990	36,062,702	36,991,692	1,438,423	39,551,848	40,990,271	81,980,542	2
VARIOUS								3
								4
								5
VARIOUS	176,265	8,585,338	8,761,603		9,587,492	9,763,757	19,351,249	6
								7
	5,736,253		5,736,253					8
								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
	28,566,445	369,747,512	398,313,957	6,773,672	199,328,849	227,309,396	433,411,917	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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	Adrian Tup	Adrian Sub	5.65	SP Wood	19.60	1	1
2	Starkey	Mccall	17.61	SP Wood	17.60	1	1
3	Starkey	Mccall	3.80	H Wood	6.58	1	1
4	Starkey	Mccall	2.08	SP Steel	17.60	2	2
5	Starkey	Mccall	1.50	SP Steel	17.60	1	1
6							
7							
8							
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							
42							
43							
44	TOTAL		30.64		78.98	6	6

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
397.5	ACSR	TVS 5'	69	13,254	1,091,584	1,104,838		2,209,676	1
715.5	ACSR	TVS 7'	138	9,697	6,715,361	6,725,058		13,450,116	2
715.5	ACSR	Hor 16'	138						3
715.5	ACSR	TVSDC 6'	138						4
715.5	ACSR	TVS 7'	138						5
									6
									7
									8
									9
									10
									11
									12
									13
									14
									15
									16
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									43
				22,951	7,806,945	7,829,896		15,659,792	44

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/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	Adelaide	transmission	345.00	138.00	13.80
2	Aiken	distribution	46.00	13.00	
3	Alameda	distribution	46.00	13.00	
4	Alameda	distribution	138.00	13.00	
5	American Falls PP - attended	transmission	138.00	13.80	
6	American Falls	transmission	138.00	46.00	12.50
7	Artesian	distribution	46.00	13.00	
8	Bannock Creek	distribution	46.00	13.00	
9	Bennett Mountain Power Plant	transmission	230.00	18.00	
10	Bennett Mountain Power Plant	transmission	18.00	4.16	
11	Bethel Court	distribution	138.00	13.00	
12	Black Cat	distribution	138.00	13.09	
13	Blackfoot	distribution	46.00	12.50	
14	Blackfoot	distribution	161.00	46.00	12.47
15	Bliss - attended	transmission	138.00	13.80	
16	Blue Gulch	distribution	138.00	34.50	
17	Boise Bench - attended	distribution	138.00	34.50	
18	Boise Bench - attended	transmission	138.00	69.00	13.80
19	Boise Bench - attended	transmission	230.00	138.00	13.80
20	Boise	distribution	138.00	13.00	
21	Borah	transmission	345.00	230.00	13.80
22	Bowmont	distribution	69.00	46.00	6.90
23	Bowmont	distribution	138.00	34.50	
24	Bowmont	transmission	138.00	69.00	13.80
25	Brady	transmission	46.00	12.50	
26	Brady	transmission	230.00	138.00	13.80
27	Brownlee - attended	transmission	230.00	13.80	
28	Bruneau Bridge	distribution	138.00	34.50	
29	Buckhorn	distribution	69.00	35.00	
30	Bucyrus	distribution	46.00	7.20	
31	Buhl	distribution	46.00	13.00	
32	Burley Rural	distribution	69.00	13.00	
33	Butler	distribution	138.00	13.00	
34	Caldwell	distribution	138.00	13.00	
35	Caldwell	distribution	138.00	69.00	13.00
36	Caldwell	transmission	230.00	138.00	12.50
37	Canyon Creek	distribution	138.00	34.50	
38	Canyon Creek	transmission	138.00	69.00	12.50
39	Cascade Power Plant - attended	transmission	69.00	4.60	
40	Cascade	Distribution	69.00	13.10	

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.
300	2					1
20	2					2
15	1					3
18	1					4
72	1					5
25	1					6
10	1					7
10	1					8
135	1					9
5	1					10
15	1					11
24	1					12
30	2					13
130	4	1				14
69	3					15
15	1					16
42	2					17
75	3					18
494	4					19
67	3					20
450	3	1				21
8	3					22
18	1					23
50	2					24
		8				25
300	3					26
734	5	1				27
30	2					28
20	1					29
6	1	4				30
20	2					31
12	1					32
48	2					33
39	2	1				34
75	3					35
240	2					36
15	1					37
		1				38
12	1					39
10	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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	Chestnut	distribution	138.00	13.00	
2	Clear Lake - attended	transmission	46.00	2.30	
3	Cliff	transmission	138.00	46.00	12.50
4	Cloverdale	Distribution	138.00	13.00	
5	Dale	distribution	69.00	13.00	
6	Dale	distribution	138.00	34.50	
7	Dale	Transmission	138.00	46.00	12.50
8	Danskin	transmission	230.00	138.00	13.80
9	Danskin	distribution	18.00	4.16	
10	Danskin	transmission	138.00	12.00	
11	Don	distribution	138.00	7.60	
12	Don	distribution	138.00	13.20	
13	Don	distribution	138.00	13.00	
14	Don	distribution	14.00		
15	DRAM	distribution	138.00	13.00	
16	DRAM	distribution	230.00	138.00	13.80
17	Duffin	distribution	138.00	34.50	
18	Eagle	distribution	138.00	13.00	
19	Eastgate	distribution	138.00	13.00	
20	Eckert	distribution	138.00	36.20	
21	Eden	distribution	138.00	34.50	
22	Eden	distribution	138.00	46.00	12.50
23	Elkhorn	distribution	138.00	12.00	
24	Elmore	transmission	138.00	34.50	
25	Elmore	distribution	138.00	69.00	12.50
26	Emmett	distribution	138.00	12.50	
27	Emmett	Transmission	138.00	69.00	12.50
28	Falls	distribution	46.00	12.50	
29	Filer	distribution	46.00	12.50	
30	Flying H	distribution	69.00	2.40	
31	Fort Hall	distribution	46.00	12.50	
32	Fossil Gulch	distribution	138.00	34.50	
33	Fremont	transmission	138.00	46.00	12.50
34	Gary	distribution	138.00	13.00	
35	Gem	distribution	69.00	13.00	
36	Golden Valley	distribution	69.00	12.50	
37	Gowen Substation	distribution	138.00	35.00	
38	Grindstone	distribution	35.00	12.50	
39	Grove	distribution	138.00	12.50	
40	Hagerman	distribution	46.00	12.50	

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.
48	2					1
4	1					2
16	3	1				3
48	2					4
		9				5
27	1					6
25	1					7
14	1	1				8
6	1					9
96	2					10
		1				11
108	6	1				12
26	1					13
80	6					14
134	8					15
160	2					16
36	2					17
38	2					18
36	2					19
18	1					20
24	1					21
15	1					22
15	2					23
17	1					24
30	2					25
15	1					26
25	1					27
17	2					28
10	1					29
15	2					30
10	1	1				31
15	1					32
50	3	1				33
36	2					34
17	2					35
10	1	1				36
24	1					37
10	2					38
72	3					39
15	2	1				40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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	Hailey	distribution	138.00	12.50	
2	Happey Valley	distribution	138.00	13.09	
3	Haven	distribution	46.00	34.50	
4	Haven	transmission	138.00	46.00	
5	Hewlett Packard	distribution	138.00	13.10	
6	Hidden Springs	distribution	138.00	13.09	
7	Highland	distribution	138.00	13.09	
8	Hill	distribution	138.00	12.50	
9	Hillsdale	distribution	138.00		
10	Homedale	distribution	69.00	12.50	
11	Horse Flat	transmission	230.00	138.00	13.80
12	Horseshoe Bend	distribution	35.00	12.50	
13	Horseshoe Bend	distribution	69.00	36.20	
14	Horseshoe Bend	distribution	69.00	25.00	
15	Huston	distribution	69.00	13.00	
16	Hulen	distribution	46.00	13.00	
17	Hunt	transmission	230.00	138.00	13.80
18	Hydra	distribution	138.00	34.50	
19	Island	distribution	69.00	12.50	
20	Jerome	distribution	138.00	12.50	
21	Julion Clawson	distribution	138.00	34.50	
22	Joplin	distribution	138.00	13.00	
23	Joplin	distribution	138.00	35.00	
24	Karcher	distribution	138.00	13.09	
25	Kenyon	distribution	69.00	12.50	
26	Ketchum	distribution	138.00	12.50	
27	Kinport	transmission	161.00	46.00	13.00
28	Kinport	transmission	230.00	138.00	12.50
29	Kinport	transmission	230.00	138.00	13.80
30	Kinport	transmission	345.00	230.00	13.80
31	Kramer	distribution	138.00	34.50	
32	Kramer	distribution	138.00	13.00	
33	Kuna	distribution	138.00	13.00	
34	Lake Fork	distribution	138.00	36.20	
35	Lake Fork	transmission	138.00	69.00	12.50
36	Lamb	distribution	138.00	13.09	
37	Lansing	distribution	69.00	13.00	
38	Lincoln	distribution	138.00	13.00	
39	Linden	distribution	138.00	13.00	
40	Locust	distribution	138.00	34.50	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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.
20	1					1
18	1					2
12	1					3
		1				4
20	1					5
8	1					6
18	1					7
24	1					8
24	1					9
20	2					10
100	1					11
5	1					12
12	1					13
5	1					14
10	1					15
10	1					16
300	3					17
24	1					18
12	1					19
40	2					20
30	2					21
15	1					22
18	1					23
12	1					24
20	2					25
42	2					26
		7				27
180	1					28
180	1					29
600	3	1				30
12	1					31
18	1					32
15	1					33
18	1					34
15	1					35
18	1					36
12	1					37
10	1					38
33	2					39
48	2					40

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	Locust	transmission	230.00	138.00	13.00
2	Lower Malad - attended	transmission	138.00	7.20	
3	Lower Salmon - attended	transmission	138.00	13.80	
4	Map Rock	distribution	69.00	12.50	
5	McCall	distribution	69.00	12.50	
6	McCall	distribution	138.00	35.00	
7	McCall	transmission	138.00	69.00	13.09
8	Meridian	distribution	138.00	13.00	
9	Micron	distribution	138.00	12.50	
10	Midpoint	transmission	230.00	138.00	13.80
11	Midpoint	transmission	345.00	230.00	13.80
12	Midpoint	transmission	500.00	345.00	
13	Midrose	distribution	138.00	13.09	
14	Milner	distribution	138.00	69.00	12.47
15	Milner	distribution	69.00	46.00	6.90
16	Milner	distribution	138.00	34.50	
17	Milner PP - attended	transmission	138.00	13.80	
18	Moonstone	distribution	138.00	34.50	
19	Mora	distribution	138.00	34.50	
20	Moreland	distribution	46.00	12.50	
21	Moreland	distribution	46.00	34.50	12.50
22	Mountain Home	distribution	69.00	12.50	
23	Mountain Home Air Force Base	distribution	69.00	12.50	
24	Mountain Home Air Force Base	distribution	138.00	12.50	
25	Nampa	distribution	230.00	138.00	13.80
26	Nampa	distribution	138.00	12.50	
27	New Meadows	distribution	69.00	35.00	
28	New Plymouth	distribution	69.00	12.50	
29	Notch Butte	distribution	13.00	7.56	
30	Orchard	distribution	69.00	13.00	
31	Orchard	distribution	69.00	35.00	12.47
32	Parma	distribution	69.00	12.50	
33	Parma	distribution	69.00	34.50	
34	Paul	distribution	138.00	34.50	12.50
35	Payette	distribution	138.00	12.50	
36	Pingree	transmission	138.00	46.00	12.50
37	Pingree	distribution	138.00	36.00	
38	Pleasant Valley	distribution	138.00	34.50	
39	Pocatello	distribution	46.00	12.50	
40	Portneuf	distribution	138.00	36.20	

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Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2009	End of 2008/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.
360	2					1
15	1					2
70	4					3
10	1					4
8	1					5
18	1					6
30	1					7
36	2					8
48	4					9
120	1					10
720	2					11
750	3	1				12
18	1					13
100	4					14
10	4					15
16	1					16
36	1					17
12	1					18
39	2					19
13	2					20
10	3	1				21
15	1					22
		1				23
18	1					24
180	1					25
50	3					26
12	1					27
10	1					28
11	1					29
4	1					30
16	4					31
10	1					32
12	1					33
36	2					34
22	3					35
50	3					36
22	2					37
42	2					38
36	2					39
18	1					40

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

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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	Portneuf	distribution	46.00	35.00	
2	Rockford	distribution	46.00	12.50	
3	Russett	distribution	138.00	12.50	
4	Sailor Creek	distribution	138.00	2.40	
5	Sailor Creek	distribution	138.00	34.50	
6	Salmon	distribution	69.00	12.50	
7	Salmon	distribution	69.00	34.50	12.50
8	Shoshone	distribution	46.00	13.00	
9	Shoshone	distribution	46.00	7.20	
10	Shoshone Falls - attended	transmission	46.00	2.30	
11	Shoshone Falls - attended	transmission	46.00	6.60	
12	Silver	distribution	138.00	34.50	
13	Simplot	distribution	138.00	12.50	
14	Sinker Creek	distribution	138.00	34.50	
15	Siphon	distribution	138.00	34.50	
16	South Park	distribution	46.00	13.00	
17	Star	distribution	138.00	13.00	
18	Starkey	Transmission	138.00	69.00	12.50
19	State	distribution	69.00	12.50	
20	Stoddard	distribution	138.00	13.00	
21	Strike Power Plant - attended	transmission	138.00	13.80	
22	Sugar	distribution	138.00	34.50	
23	Swan Falls - attended	transmission	138.00	6.90	
24	Taber	distribution	46.00	12.50	
25	Ten Mile	distribution	138.00	13.09	
26	Terry	distribution	138.00	12.50	
27	Thousand Springs - attended	transmission	46.00	6.90	
28	Thousand Springs - attended	transmission	7.00	2.40	
29	Toponis	distribution	138.00	34.50	
30	Twin Falls	distribution	138.00	13.00	
31	Twin Falls	transmission	138.00	46.00	12.50
32	Twin Falls PP - attended	transmission	138.00	7.20	
33	Twin Falls PP - attended	transmission	138.00	13.20	
34	Upper Malad - attended	transmission	46.00	7.20	
35	Upper Salmon- attended	transmission	138.00	7.20	
36	Ustick	distribution	138.00	12.50	
37	Vallivue	distribution	138.00	13.09	
38	Victory	distribution	138.00	12.50	
39	Ware	distribution	69.00	12.50	
40	Weiser	distribution	69.00	12.50	

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SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
		1				1
14	2					2
18	1					3
15	2					4
15	1					5
10	1	4				6
10	3	1				7
10	1	1				8
2	3					9
3	1					10
10	1					11
12	1					12
15	1					13
12	1					14
33	2					15
10	1					16
18	1					17
18	1					18
33	2					19
15	1					20
83	3					21
20	2					22
18	1					23
5	1					24
24	1					25
42	3					26
8	1					27
2	1					28
18	1					29
44	2					30
33	2					31
9	1					32
72	1					33
8	1					34
36	4					35
44	2					36
18	1					37
24	1					38
12	1					39
20	2					40

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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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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	Weiser	transmission	138.00	69.00	12.50
2	Wilder	distribution	69.00	13.00	
3	Willis	distribution	138.00	13.09	
4	Wye	distribution	138.00	13.00	
5	Zilog	distribution	138.00	13.09	
6					
7					
8	The above are all State of Idaho				
9					
10	Montana:				
11	Peterson	transmission	230.00	69.00	13.20
12					
13	Nevada:				
14	Valmy - attended	transmission	345.00	21.30	
15	Wells	transmission	138.00	69.00	12.50
16					
17	Oregon:				
18	Boardman - attended	transmission	500.00	24.00	
19	Cairo	distribution	69.00	12.50	
20	Hells Canyon - attended	transmission	230.00	13.80	
21	Hines	transmission	138.00	115.00	12.50
22	Malheur Butte	distribution	69.00	34.50	12.50
23	Nyssa	distribution	69.00	12.50	
24	Ontario	distribution	138.00	12.50	
25	Ontario	distribution	138.00	69.00	12.50
26	Ontario	distribution	230.00	138.00	13.80
27	Ore-Ida	distribution	69.00	12.50	
28	Oxbow - attended	transmission	138.00	69.00	13.00
29	Oxbow - attended	transmission	230.00	13.80	
30	Oxbow - attended	transmission	230.00	138.00	13.80
31	Quartz	transmission	138.00	69.00	12.50
32	Quartz	transmission	230.00	138.00	13.00
33	Vale	distribution	69.00	13.09	
34					
35	Wyoming:				
36	Jim Bridger - attended	transmission	345.00	22.00	
37					
38					
39					
40					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2009	Year/Period of Report End of 2008/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)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
25	1					1
10	1					2
18	1					3
56	3					4
24	1					5
						6
						7
						8
						9
						10
20	2	2				11
						12
						13
150	1					14
20	3	1				15
						16
						17
55	1					18
12	1					19
501	4					20
40	1					21
8	3	1				22
20	2					23
38	2					24
75	3	1				25
240	2					26
15	1					27
10	3	1				28
244	2					29
100	1					30
30	2					31
100	3	1				32
10	1					33
						34
						35
748	1					36
						37
						38
						39
						40

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SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1					
2					
3	Transformers-distribution substations under 10,000				
4	KVA 88 unattended.				
5					
6					
7					
8					
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					

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SUBSTATIONS (Continued)

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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)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
						2
						3
350						4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
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						36
						37
						38
						39
						40

ANNUAL REPORT

IDAHO SUPPLEMENT TO FERC FORM 1

MULTI-STATE ELECTRIC COMPANIES

INDEX

Page Number	Title
1	Statement of Income for the Year
2	Taxes Allocated to Idaho
3	Notes and Accounts Receivable
3	Accumulated Provision for Uncollectible Accounts
4	Receivables from Associated Companies
5	Gain or Loss on Disposition of Property
6	Professional or Consultative Services
7-10	Electric Plant in Service
11	Electric Operating Revenues
12-15	Electric Operation and Maintenance Expenses
15	Number of Electric Department Employees

STATEMENT OF INCOME FOR THE YEAR

1. Report amounts for accounts 412 and 413, Revenue and Expenses from Utility Plant Leased to Others, in another utility column (i,k,m,o) in a similar manner to a utility department. Spread the amount(s) over lines 01 thru 24 as appropriate. Include these amounts in columns (c) and (d) totals.
2. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
3. Report data for lines 7, 9, and 10 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1, and 407.2.
4. Use page 122 for important notes regarding the state ment of income or any account thereof.
5. 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 a material refund to the utility with respect to power or gas purchases. State for each year affected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of retain such revenues or recover amounts paid with respect to power and gas purchases.
6. Give concise explanations concerning significant amounts of any refunds made or received during the year.

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	11	$ 910,245,287	$ 841,478,350
3	Operating Expenses			
4	Operation Expenses (401)	15	550,991,682	517,569,128
5	Maintenance Expenses (402)	15	64,078,869	63,803,165
6	Depreciation Expense (403)		89,690,866	88,365,074
7	Amort. & Depl. of Utility Plant (404-405)		4,622,992	4,925,898
8	Amort. of Utility Plant Acq. Adj. (406)			
9	Amort. of Property Losses, Unrecovered Plant and			
10	Regulatory Study Costs (407)			
11	Amort. of Conversion Expenses (407)			
12	Regulatory Debits/Credits (407.3 & 407.4)		(3,781,013)	2,114,441
13	Taxes Other Than Income Taxes (408.1)	2	17,214,058	15,922,687
14	Income Taxes - Federal (409.1)	2	(1,876,222)	2,592,539
15	- Other (409.1)	2	(5,091,963)	(6,483,885)
16	Provision for Deferred Income Taxes (410.1 & 411.1) Net	2	41,638,625	34,515,479
17	Investment Tax Credit Adj. - Net (411.4)	2	2,343,614	1,862,104
18	(Less) Gains from Disp. of Utility Plant (411.6)			
19	Losses from Disp. of Utility Plant (411.7)			
20	(Less) Gains from Disposition of Allowances (411.8)			
21	Losses from Disposition of Allowances (411.9)			
22				
23	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 22)		759,831,509	725,186,631
24				
25	Net Utility Operating Income (Enter Total of line 2 less 23)			
26	(Carry forward to page 11, line 27)		$ 150,413,778	$ 116,291,719

TAXES ALLOCATED TO IDAHO

Kind of Tax	Taxes Charged During Year
Taxes Other Than Income Taxes:	
Labor Related:	
FICA	$ 10,762,704
FUTA	117,126
State Unemployment	176,070
Payroll Deduction & Loading	(11,055,900)
Total Labor Related	0
Property Taxes	13,987,518
Kilowatt-hour Tax	1,242,360
Licenses	3,169
Regulatory Commission Fees	1,728,039
Irrigation PIC	252,972
Total Taxes Other Than Income Taxes	17,214,058
Federal Income Taxes	(1,876,222)
State Income Taxes	(5,091,963)
Deferred Income Taxes	41,638,625
Investment Tax Credit Adjustment - Net	2,343,614
Total Taxes Allocated to Idaho	$ 54,228,112

NOTES AND ACCOUNTS RECEIVABLE

Summary for Balance Sheet

Show separately by footnote the total amount of notes and accounts receivable from directors, officers, and employees included in Notes Receivable (Account 141) and Other Accounts Receivable (Account 143)

Line No.	Accounts (a)	Balance Beginning of Year (b)	Balance End of Year (c)
1	Notes Receivable (Account 141)	$ 5,975,468	$ 1,549,041
2	Customer Accounts Receivable (Account 142)	62,122,209	64,433,173
3	Other Accounts Receivable (Account 143)	7,080,171	6,557,937
4	(Disclose any capital stock subscription received)		
5	Total	$ 75,177,848	$ 72,540,152
6			
7	Less: Accumulated Provision for Uncollectible		
8	Accounts-Cr. (Account 144)	1,305,058	1,723,936
9			
10	Total, Less Accumulated Provision for		
11	Uncollectible Accounts	$ 73,872,789	$ 70,816,216
12			
13			
14	Notes Receivable - Account 141: (at 12-31-08)		
15	Directors, officers, and employees - $ 232,483		
16			
17			
18	Other Accounts Receivable - Account 143: (at 12-31-08)		
19	Directors, officers, and employees - $ 2,246		
20			

ACCUMULATED PROVISION FOR UNCOLLECTIBLE ACCOUNTS - CR. (Account 144)

1. Report below the information called for concerning this accumulated provision.
2. Explain any important adjustments of subaccounts.
3. Entries with respect to officers and employees shall not include items for utility services.

Line No.	Item (a)	Utility Customers (b)	Mdse, Jobbing & Contract Work (c)	Officers and Employees (d)	Other (e)	Total (f)
21						
22	Bal. beginning of year	$ 1,163,632	$	$	$ 331,180	1,494,812
23	Prov. for uncollectibles					
24	for year	141,427			87,697	229,124
25	Accounts written off					
26	Coll. of accounts					
27	written off					
28	Adjustments (explain)					
29						
30						
31						
32	Balance end of year	$ 1,305,058	$ -	$ -	$ 418,877	$ 1,723,936
33						

RECEIVABLES FROM ASSOCIATED COMPANIES (Accounts 145, 146)

1. Report particulars of notes and accounts receivable from associated companies at end of year.

2. Provide separate headings and totals for accounts 145, Notes Receivable from Associated Companies, and 146, Accounts Receivable from Associated Companies, in addition to a total for the combined accounts.

3. For notes receivable list each note separately and state purpose for which received. Show also in column (a) date of note, date of maturity and interest rate.

4. If any note was received in satisfaction of an open account, state the period covered by such open account.

5. Include in column (f) interest recorded as income during the year, including interest on accounts and notes held at any time during the year.

6. Give particulars of any notes pledged or discounted, also of any collateral held as guarantee of payment of any note or account.

Line No.	Particulars (a)	Balance Beginning of Year (b)	Totals for Year Debits (c)	Totals for Year Credits (d)	Balance End of Year (e)	Interest For Year (f)
1	Account 145:					
2						
3	IERCO................................	$ 21,527,626	$ 48,593,324	$ 43,541,179	$ 26,579,771	
4						
5						
6						
7						
8						
9						
10	Total Account 145..................	21,527,626	48,593,324	43,541,179	26,579,771	
11						
12	Account 146:					
13						
14						
15						
16	IDACORP, Inc........................	$ -	$ 3,274,632	$ 3,276,644	$ (2,011)	
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31	Total Account 146........................	$ -	$ 3,274,632	$ 3,276,644	$ (2,011)	
32						

STATE OF IDAHO - TOTAL SYSTEM DATA

GAIN OR LOSS ON DISPOSITION OF PROPERTY (Account 421.1 and 421.2)

1. Give a brief description of property creating the gain or loss. Include name of party acquiring the property (when acquired by another utility or associated company) and the date transaction was completed. Identify property by type; Leased, Held for Future Use, or Nonutility.

2. Individual gains or losses relating to property with an original cost of less than $50,000 may be grouped, with the number of such transactions disclosed in column (a).

3. Give the date of Commission approval of journal entries in column (b), when approval is required. Where approval is required but has not been received, give explanation following the item in column (a). (See account 102, Utility Plant Purchased or Sold.)

Line No.	Description of Property (a)	Original Cost of Related Property (b)	Date Journal Entry Approved (When Required) (c)	Acct 421.1 (d)	Acct 421.2 (e)
1	Gain on disposition of				
2	property:				
3					
4	Inkom Junction	17,796	2/27/2008	$ 78,728	
5					
6	Gain on sale of SWIP	3,465,186	6/9/2008	$ 3,011,327	
7					
8	Misc Items (2)	64,479		(38,548)	
9					
10					
11					
12					
13					
14	Total gain............	$ 3,547,461		$ 3,051,506	
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31	Total loss............	$ 0			$ 0

STATE OF IDAHO - TOTAL SYSTEM DATA

PROFESSIONAL OR CONSULTATIVE SERVICES - ITEMS $10,000 AND OVER

Line No.	PAYEE (a)	SERVICE TYPE (b)	Amount (c)
1	AERO-GRAPHICS	Mapping Services	$ 47,682
2	BARKER, ROSHOLT & SIMPSON LLP	Legal Services	502,770
3	BIDART & ROSS INC	Management Services	32,350
4	BLUE HERON CONSULTING, INC	Legal Services	269,942
5	BOUILLON INTEGRATED SYSTEMS, I	Computer Support Services	96,160
6	BRENNEMAN, JOHN	Lobby Services	73,053
7	BRIGHAM YOUNG UNIVERSITY	Environmental Services	45,000
8	BROWN RUDNICK BERLACK ISRAELS	Lobby Services	72,000
9	BROWNSTEIN HYATT & FARBER, P C	Legal Services	2,405,630
10	BUREAU OF LAND MANAGEMENT	Environmental Services	130,000
11	CADMUS GROUP INC, THE	Architect Services	58,256
12	CASCADE ENERGY ENGINEERING INC	Engineering Services	84,347
13	CEDARCRESTONE INC	Computer Support Services	64,800
14	CHURCH, JOHN S	Economic Services	78,000
15	CLEAREDGE PARTNERS INC	Computer Support Services	79,500
16	COMMVAULT SYSTEMS, INC	Computer Support Services	22,000
17	COMSYS INFORMATION TECHNOLOGY	Computer Support Services	518,100
18	CORNERSTONE SYSTEMS INC	Computer Support Services	1,239,569
19	CSHQA	Architect Services	106,326
20	CTA ARCHITECTS	Architect Services	13,443
21	DAVID EVANS AND ASSOCIATES	Management Services	98,670
22	DAVIS WRIGHT TREMAINE LLP	Legal Services	505,494
23	DELOITTE & TOUCHE	Accounting Services	321,884
24	DEVINE, TARBELL & ASSOC INC	Engineering Services	20,308
25	DEWEY & LEBOEUF	Legal Services	3,823,131
26	DHI INC	Environmental Services	71,996
27	ECOANALYSTS INC	Environmental Services	194,083
28	ECOTOPE	Architect Services	34,142
29	EMC CORPORATION	Computer Support Services	23,309
30	ENTERPRISE ELECTRIC, INC.	Management Services	18,677
31	ERNST & YOUNG LLP	Accounting Services	27,785
32	EVANS KEANE	Legal Services	13,151
33	FALASH & ROSS CONSTRUCTION INC	Management Services	14,749
34	GILBERT, DAN D	Meteorological Services	28,600
35	GLOBAL INSIGHT	Environmental Services	25,057
36	HARDESTY, REBECCA	Environmental Services	105,214
37	HONEYWELL INTERNATIONAL INC	Environmental Services	10,115
38	HOPKINS RODEN CROCKETT HANSEN	Lobby Services	72,000
39	HR MANAGEMENT SOLUTIONS LLC	Management Services	19,594
40	HYQUAL	Environmental Services	110,047
41	INTERMOUNTAIN TECHNOLOGY GROUP	Computer Support Services	30,720
42	IOWA INSTITUTE OF HYDRAULICS	Consulting Services	11,735
43	JONES AND SWARTZ PLLC	Legal Services	226,146
44	JUB ENGINEERS	Engineering Services	27,306
45	KPMG LLP	Accounting Services	133,554

STATE OF IDAHO - TOTAL SYSTEM DATA

PROFESSIONAL OR CONSULTATIVE SERVICES - ITEMS $10,000 AND OVER

Line No.	PAYEE (a)	SERVICE TYPE (b)	Amount (c)
46	L CONWAY CONSULTING, INC	Consulting Services	$ 37,327
47	MAGIC WATER	Consulting Services	14,904
48	MANAGEMENT NORTHWEST	Legal Services	68,655
49	MCCLURE ENGINEERING	Engineering Services	18,000
50	MCDOWELL & RACKNER PC	Legal Services	148,229
51	MIRANDE, MICHAEL	Legal Services	76,712
52	MODULA4 LLC	Computer Support Services	22,497
53	MODUS ARCHITECTURE	Architect Services	319,487
54	MOEN, MONICA B	Legal Services	10,439
55	MUSGROVE ENGINEERING PA	Engineering Services	19,478
56	NEXANT INC	Computer Support Services	109,332
57	NIELSEN GROUP INC, THE	Consulting Services	134,793
58	OFFICE ENVIRONMENT COMPAN	Management Services	18,697
59	OLIVER, RUSSELL & ASSOC. INC	Environmental Services	15,000
60	OREGON STATE DEPARTMENT OF ENE	Environmental Services	50,000
61	PAINE, HAMBLEN, COFFIN , BROOK	Management Services	338,396
62	PAPPALARDO CONSTRUCTION	Construction Services	19,448
63	PARR WADDOUPS BROWN GEE AND LO	Environmental Services	108,183
64	PEAK SCIENCE COMMUNICATIONS	Management Services	60,993
65	PEASLEY TRANSFER & STORAGE CO	Management Services	25,054
66	PHONE PRO	Management Services	15,553
67	PINK ELEPHANT CORP	Computer Support Services	12,826
68	PLANNEDSCAPE	Consulting Services	45,620
69	PORTLAND ENERGY CONSERVATION,	Environmental Services	169,477
70	PUBLIC OPINION STRATEGIES LLC	Management Services	16,000
71	R W BECK	Consulting Services	70,356
72	RIDDELL WILLIAMS P.S.	Legal Services	27,391
73	RIPLEY, LARRY D	Legal Services	20,300
74	RIVERSIDE TECHNOLOGY INC	Management Services	119,792
75	S G S STATISTICAL SERVICES	Consulting Services	14,250
76	SALLADAY & DAVIS	Legal Services	64,671
77	SCIENCE APPLICATIONS INTE	Environmental Services	12,848
78	SOFTWARE AG INC	Computer Support Services	109,760
79	SOLID QUALITY LEARNING LLC	Computer Support Services	28,319
80	SOS STAFFING SERVICES	Management Services	24,466
81	SPHERION STAFFING AND RECRUITI	Management Services	236,704
82	SPINK BUTLER LLP	Legal Services	19,411
83	ST LUKES REGIONAL MEDICAL	Consulting Services	10,000
84	STATE OF IDAHO FISH & GAME	Environmental Services	100,000
85	STATISTICAL DESIGN	Consulting Services	33,681
86	STEPTOE & JOHNSON LLP	Legal Services	317,682
87	STOEL RIVES LLP	Legal Services	88,458
88	STRUCTURED	Engineering Services	100,035
89	SULLIVAN & CROMWELL	Management Services	169,362

STATE OF IDAHO - TOTAL SYSTEM DATA

PROFESSIONAL OR CONSULTATIVE SERVICES - ITEMS $10,000 AND OVER

Line No.	PAYEE (a)	SERVICE TYPE (b)	Amount (c)
90	SWCA, INC	Environmental Services	19,292
91	TEKSYSTEMS	Computer Support Services	248,353
92	TETRA TECH INC	Consulting Services	11,851
93	TOWERS PERRIN HR SERVICES	Management Services	43,303
94	TREASURE VALLEY LEGAL SERVICES	Legal Services	67,776
95	TROUT, JONES, GLEDHILL, FUHRMA	Legal Services	19,070
96	UNIVERSITY OF IDAHO	Environmental Services	93,400
97	VAN NESS FELDMAN	Legal Services	921,135
98	VAN WINKLE ENVIRONMENTAL CONSU	Environmental Services	15,400
99	WEATHER DECISION TECHNOLOGIES	Meteorological Services	17,936
100	WEATHER MODIFICATION INC	Cloud Seeding Services	274,392
101	YTURRI& ROSE& BURNHAM& BENTZ	Legal Services	65,544
1	TOTAL		17,146,431

PROFESSIONAL OR CONSULTATIVE SERVICES

ITEMS $5,000 OR MORE BUT LESS THAN $10,000

Line No.	PAYEE	PREDOMINANT NATURE OF SERVICE	AMOUNT
1	BAKER, KEN	Management Services	5,000
2	BINDA, CHERYL E	Consulting Services	8,025
3	CEDAR CREST CORP	Computer Support Services	7,826
4	CERTUS SOFTWARE INC	Computer Support Services	6,375
5	CONNOR CLAIMS SPECIALISTS	Consulting Services	6,882
6	CORPORATE EXECUTIVE BOARD	Management Services	8,850
7	DATA ONE LLC	Computer Support Services	5,853
8	ECOS CONSULTING	Consulting Services	5,771
9	FINANCIAL CONCEPTS AND APPLICA	Management Services	6,100
10	GJORDING & FOUSER, PLLC	Management Services	6,111
11	HALL FARLEY OBERRECHT & B	Legal Services	8,864
12	HEINZ FROZEN FOODS	Consulting Services	6,186
13	HOLLAND LAW OFFICE, P C	Legal Services	7,125
14	MERCER HEALTH & BENEFITS	Consulting Services	9,000
15	MILLER BATEMAN LLP	Legal Services	8,459
16	NEUROLOGICAL ASSOCIATES	Environmental services	7,374
17	PACIFICORP	Consulting Services	5,338
18	PANTER, GREGORY W	Lobby Services	9,000
19	PLATEAU SYSTEMS LTD	Computer Support Services	9,600
20	POWER ENGINEERS INC	Engineering Services	9,039
21	QUANTEC LLC	Computer Support Services	6,121
22	SMITH, CURTIS D	Meteorological Services	7,546
23	STAHMAN, ROBERT W	Legal Services	5,500
24	SWANSON ENTERPRISES LLC	Management Services	5,517
25	TOOTHMAN-ORTON ENGINEERING	Engineering Services	8,049
26	TREASURE VALLEY ENGINEERS INC	Engineering Services	8,100
27	UTZ, AARON D	Environmental services	6,956
28	WRUBLE WILDLAND SERVICES	Environmental services	8,333
29			
30			
31			
32			
33			
34			
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42			
43			
44			
45	**TOTAL**		202,901

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ELECTRIC PLANT IN SERVICE (Accounts 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. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
5. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c) . Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements 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 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.

Line No.	Account (a)	Balance at Beginning of year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	$ 5,289	
3	(302) Franchises and Consents	20,729,010	
4	(303) Miscellaneous Intangible Plant	45,458,188	
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	66,192,487	
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights		
9	(311) Structures and Improvements		
10	(312) Boiler Plant Equipment		
11	(313) Engines and Engine Driven Generators		
12	(314) Turbogenerator Units		
13	(315) Accessory Electric Equipment		
14	(316) Misc. Power Plant Equipment		
15	(317) Asset Retirement Costs for Steam Production	4,751,512	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	824,234,217	
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 17 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights		
28	(331) Structures and Improvements		
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment		
32	(335) Misc. Power Plant Equipment		
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	635,772,428	
36	D. Other Production Plant		
37	(340) Land and Land Rights		
38	(341) Structures and Improvements		
39	(342) Fuel Holders, Products and Accessories		
40	(343) Prime Movers		
41	(344) Generators		
42	(345) Accessory Electric Equipment		
43	(346) Misc Power Plant Equipment		

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

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

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

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
			$ 51,819	(301)	2
			20,695,155	(302)	3
			30,625,097	(303)	4
			51,372,071		5
					6
					7
				(310)	8
				(311)	9
				(312)	10
				(313)	11
				(314)	12
				(315)	13
				(316)	14
			4,378,761	(317)	15
			846,472,518		16
					17
				(320)	18
				(321)	19
				(322)	20
				(323)	21
				(324)	22
				(325)	23
				(326)	24
					25
					26
				(330)	27
				(331)	28
				(332)	29
				(333)	30
				(334)	31
				(335)	32
				(336)	33
				(337)	34
			651,906,341		35
					36
				(340)	37
				(341)	38
				(342)	39
				(343)	40
				(344)	41
				(345)	42
				(345)	43

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

Line No.	Account (a)	Balance at Beginning of year (b)	Additions (c)
44	(346) Misc. Power Plant Equipment		
45	TOTAL Other Production Plant (Enter Total of lines 37 thru 44)	$ 101,426,503	
46	TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 45)	1,561,433,148	
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	26,624,995	
49	(352) Structures and Improvements	34,464,805	
50	(353) Station Equipment	224,406,655	
51	(354) Towers and Fixtures	104,698,993	
52	(355) Poles and Fixtures	73,602,511	
53	(356) Overhead Conductors and Devices	118,628,677	
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices		
56	(359) Roads and Trails	261,238	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	582,687,874	
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	4,177,113	
61	(361) Structures and Improvements	20,581,394	
62	(362) Station Equipment	144,293,516	
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	187,646,959	
65	(365) Overhead Conductors and Devices	99,310,499	
66	(366) Underground Conduit	45,493,283	
67	(367) Underground Conductors and Devices	168,166,353	
68	(368) Line Transformers	320,594,439	
69	(369) Services	51,079,812	
70	(370) Meters	53,914,672	
71	(371) Installations on Customer Premises	2,446,858	
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	3,916,181	
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,101,621,080	
76	5. GENERAL PLANT		
77	(389) Land and Land Rights	8,229,314	
78	(390) Structures and Improvements	63,800,301	
79	(391) Office Furniture and Equipment	35,424,379	
80	(392) Transportation Equipment	53,102,346	
81	(393) Stores Equipment	996,702	
82	(394) Tools, Shop, and Garage Equipment	4,090,231	
83	(395) Laboratory Equipment	9,489,976	
84	(396) Power Operated Equipment	8,077,988	
85	(397) Communication Equipment	24,014,386	
86	(398) Miscellaneous Equipment	2,806,494	
87	SUBTOTAL (Enter Total of lines 77 thru 86)	210,032,117	
88	(399) Other Tangible Property		
89	(399.1) Asset Retirement Costs for General Plant		
90	TOTAL General Plant (Enter Total of lines 87, 88 and 89)	210,032,117	
91	TOTAL (Accounts 101 and 106)	3,521,966,706	
92	(102) Electric Plant Purchased		
93	(Less) (102) Electric Plant Sold		
94	(103) Experimental Plant Unclassified		
95			
96	TOTAL Electric Plant in Service	$ 3,521,966,706	

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.
				(346)	44
			$ 157,012,463		45
			1,655,391,322		46
					47
			29,508,846	(350)	48
			35,140,814	(352)	49
			242,900,194	(353)	50
			117,045,225	(354)	51
			77,089,121	(355)	52
			126,757,259	(356)	53
				(357)	54
				(358)	55
			259,733	(359)	56
				(359.1)	57
			628,701,192		58
					59
			4,477,141	(360)	60
			23,233,750	(361)	61
			158,476,358	(362)	62
				(363)	63
			193,280,200	(364)	64
			108,838,821	(365)	65
			46,743,899	(366)	66
			176,439,252	(367)	67
			347,244,209	(368)	68
			52,673,244	(369)	69
			56,487,653	(370)	70
			2,319,885	(371)	71
				(372)	72
			3,943,911	(373)	73
				(374)	74
			1,174,158,323		75
					76
			10,029,463	(389)	77
			66,136,218	(390)	78
			42,518,018	(391)	79
			54,120,844	(392)	80
			1,095,243	(393)	81
			4,453,928	(394)	82
			9,922,115	(395)	83
			8,033,807	(396)	84
			24,184,365	(397)	85
			3,803,267	(398)	86
			224,297,268		87
				(399)	88
				(399.1)	89
			224,297,268		90
			3,733,920,176		91
				(102)	92
				(102)	93
				(371)	94
					95
			$ 3,733,920,176		96

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.

No.	(a)	OPERATING REVENUES Amount for Current Year (b)	Amount for Previous Year (c)
1	Sales of Electricity		
2	(440) Residential Sales	$ 341,596,320	$ 297,428,947
3	(442) Commercial and Industrial Sales		
4	Small (or Commercial)(See Instr. 4) (1)	294,564,569	245,919,592
5	Large (or Industrial)(See Instr. 4) (2)	113,125,182	92,303,177
6	(444) Public Street and Highway Lighting	2,784,169	2,374,374
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	752,070,239 *	638,026,089
11	(447) Sales for Resale - Opportunity....Non-Firm Only	113,059,123	159,135,233
12	TOTAL Sales of Electricity	865,129,362	797,161,322
13	(449) Provision for Rate Refunds	(5,876,173)	(1,075,534)
14	TOTAL Revenue Net of Provision for Refunds	859,253,189	796,085,788
15	**Other Operating Revenues**		
16	(450) Forfeited Discounts	-	
17	(451) Miscellaneous Service Revenues	3,611,150	3,996,236
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	16,916,322	17,049,167
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	30,464,627	24,347,160
22			
23			
24			
25	TOTAL Other Operating Revenues	50,992,098	45,392,562
26	TOTAL Electric Operating Revenues	$ 910,245,287	$ 841,478,350

(1) Commercial and Industrial sales - Small - under 1,000 KW and includes all irrigation customers.
(2) Commercial and Industrial sales - Large - 1,000 KW and over.

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 classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain
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 footnote.

KILOWATT HOURS SOLD		AVERAGE NUMBER OF CUSTOMERS PER MONTH		
Amount for Current Year (d)	Amount for Previous Year (e)	Amount for Current Year (f)	Number for Previous Year (g)	Line No.
				1
5,093,471,949	5,027,203,909	389,177	383,992	2
				3
5,648,670,010	5,622,131,528	75,605	73,726	4
3,101,515,627	3,170,394,452	114	118	5
29,990,161	28,637,063	1,237	992	6
				7
				8
				9
13,873,647,747 **	13,848,366,952	466,133	458,828	10
1,946,246,652	2,603,995,368	N/A	N/A	11
15,819,894,399	16,452,362,320	466,133	446,889	12
				13

* Includes $ 6,002,049 unbilled revenues.

** Includes 3,265,671 KWH relating to unbilled revenues.

Lines 11 through 21 are on an "allocated" basis.

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 Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	$ 1,572,838	$ 1,585,144
5	(501) Fuel	125,486,116	108,989,376
6	(502) Steam Expenses	7,011,862	6,491,790
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,728,050	2,002,446
10	(506) Miscellaneous Steam Power Expenses	7,374,383	7,681,857
11	(507) Rents	447,656	281,610
12	(509) Allowances		
13	TOTAL Operation (Enter Total of lines 4 thru 12)	143,620,904	127,032,223
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	2,447,221	2,456,682
16	(511) Maintenance of Structures	380,003	618,172
17	(512) Maintenance of Boiler Plant	13,502,507	13,885,052
18	(513) Maintenance of Electric Plant	4,088,429	5,395,860
19	(449) Provision for Rate Refunds	4,120,059	5,650,640
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	24,538,219	28,006,406
21	TOTAL Power Production Expenses-Steam Power (Enter Total of lines 13 and 20)	168,159,122	155,038,629
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-Nuclear Power (Enter Total of lines 33 and 40).		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	5,338,835	4,984,055
45	(536) Water for Power	7,010,542	4,814,932
46	(537) Hydraulic Expenses	9,510,192	9,016,462
47	(538) Electric Expenses	1,250,030	1,323,535
48	(539) Miscellaneous Hydraulic Power Generation Expenses	2,946,587	2,690,247
49	(540) Rents	411,625	399,555
50	TOTAL Operation (Enter Total of lines 44 thru 49)	26,467,811	23,228,787

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 Previous Year (c)
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	$ 1,796,685	$ 1,785,723
54	(542) Maintenance of Structures	1,298,112	1,220,450
55	(543) Maintenance of Reservoirs, Dams, and Waterways	770,378	515,125
56	(544) Maintenance of Electric Plant	2,375,483	1,988,155
57	(545) Maintenance of Miscellaneous Hydraulic Plant	2,988,642	2,630,881
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	9,229,300	8,140,333
59	TOTAL Power Production Expenses-Hydraulic Power (Enter Total of lines 50 and 58)	35,697,111	31,369,119
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	355,128	325,262
63	(547) Fuel	16,527,579	18,492,527
64	(548) Generation Expenses	385,160	363,281
65	(549) Miscellaneous Other Power Generation Expenses	505,295	442,565
66	(550) Rents	0	-
67	TOTAL Operation (Enter Total of lines 62 thru 66)	17,773,163	19,623,635
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	203	-
70	(552) Maintenance of Structures	154,756	209,865
71	(553) Maintenance of Generating and Electric Plant	188,740	40,597
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	485,322	614,836
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	829,021	865,298
74	TOTAL Power Production Expenses-Other Power (Enter Total of lines 67 and 73)	18,602,183	20,488,934
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	219,713,102	288,699,422
77	(556) System Control and Load Dispatching	74,320	73,778
78	(557) Other Expenses	(42,798,888)	(112,995,170)
79	TOTAL Other Power Supply Expenses (Enter Total of lines 76 thru 78)	176,988,534	175,778,030
80	TOTAL Power Production Expenses (Enter Total of lines 21, 41, 59, 74, and 79)	399,446,950	382,674,713
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,034,871	1,987,843
84	(561) Load Dispatching	2,469,165	2,806,393
85	(562) Station Expenses	1,532,864	1,491,967
86	(563) Overhead Line Expenses	620,324	784,669
87	(564) Underground Line Expenses		
88	(565) Transmission of Electricity by Others	6,891,722	9,936,576
89	(566) Miscellaneous Transmission Expenses	393,825	529,755
90	(567) Rents	918,540	990,555
91	TOTAL Operation (Enter Total of lines 83 thru 90)	14,861,312	18,527,758
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	365,345	376,412
94	(569) Maintenance of Structures	384,492	387,193
95	(570) Maintenance of Station Equipment	2,297,887	2,473,911
96	(571) Maintenance of Overhead Lines	2,839,970	1,987,795
97	(572) Maintenance of Underground Lines		
98	(573) Maintenance of Miscellaneous Transmission Plant	230	2,151
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	5,887,923	5,227,462
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	20,749,235	23,755,220
101	3. DISTRIBUTION EXPENSES		
102	Operation		
103	(580) Operation Supervision and Engineering	3,110,903	3,141,021

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 Previous Year (c)
104	3. DISTRIBUTION EXPENSES (Continued)		
105	(581) Load Dispatching	$ 2,955,162	$ 2,906,722
106	(582) Station Expenses	1,083,795	1,066,301
107	(583) Overhead Line Expenses	3,088,294	3,172,327
108	(584) Underground Line Expenses	2,000,668	2,085,453
109	(585) Street Lighting and Signal System Expenses	124,298	141,411
110	(586) Meter Expenses	4,440,626	4,332,721
111	(587) Customer Installations Expenses	1,278,622	1,227,727
112	(588) Miscellaneous Distribution Expenses	5,117,017	5,187,236
113	(589) Rents	427,167	604,482
114	TOTAL Operation (Enter Total of lines 103 thru 113)	23,626,553	23,865,402
115	Maintenance		
116	(590) Maintenance Supervision and Engineering	299,351	246,198
117	(591) Maintenance of Structures	2,202	-
118	(592) Maintenance of Station Equipment	3,349,705	3,322,976
119	(593) Maintenance of Overhead Lines	12,697,688	11,557,647
120	(594) Maintenance of Underground Lines	1,214,941	1,328,521
121	(595) Maintenance of Line Transformers	404,868	154,268
122	(596) Maintenance of Street Lighting and Signal Systems	631,613	453,194
123	(597) Maintenance of Meters	826,332	888,231
124	(598) Maintenance of Miscellaneous Distribution Plant	324,644	114,582
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	19,751,345	18,065,618
126	TOTAL Distribution Expenses (Enter Total of lines 114 and 125)	43,377,897	41,931,019
127	4. CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision	326,498	435,360
130	(902) Meter Reading Expenses	5,428,979	5,146,950
131	(903) Customer Records and Collection Expenses	11,328,761	7,866,032
132	(904) Uncollectible Accounts	3,524,430	1,876,639
133	(905) Miscellaneous Customer Accounts Expenses	448	320
134	TOTAL Customer Accounts Expenses (Enter Total of lines 129 thru 133)	20,609,116	15,325,300
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision	297,076	299,100
138	(908) Customer Assistance Expenses	27,459,029	21,710,324
139	(909) Informational and Instructional Expenses	0	0
140	(910) Miscellaneous Customer Service and Informational Expenses	853,596	876,111
141	TOTAL Cust. Service and Informational Expenses (Enter Total of lines 137 thru 140)	28,609,702	22,885,534
142	6. SALES EXPENSES		
143	Operation		
144	(911) Supervision		
145	(912) Demonstrating and Selling Expenses		
146	(913) Advertising Expenses		
147	(916) Miscellaneous Sales Expenses		
148	TOTAL Sales Expenses (Enter Total of lines 144 thru 147)		
149	7. ADMINISTRATIVE AND GENERAL EXPENSES		
150	Operation		
151	(920) Administrative and General Salaries	53,957,955	46,724,352
152	(921) Office Supplies and Expenses	13,871,196	16,697,245
153	(Less) (922) Administrative Expenses Transferred-Credit	(21,321,650)	(26,005,639)

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
154	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
155	(923) Outside Services Employed	$ 12,751,357	$ 10,542,564
156	(924) Property Insurance	2,899,818	2,957,019
157	(925) Injuries and Damages	7,078,580	5,113,519
158	(926) Employee Pensions and Benefits	21,419,548	26,159,168
159	(927) Franchise Requirements	1,549	1,200
160	(928) Regulatory Commission Expenses	4,251,098	5,332,170
161	(929) Duplicate Charges-Cr		
162	(930.1) General Advertising Expenses	222,095	487,897
163	(930.2) Miscellaneous General Expenses	3,296,721	3,282,233
164	(931) Rents	6,323	10,731
165	TOTAL Operation (Enter Total of lines 151 thru 164)	98,434,590	91,302,458
166	Maintenance		
167	(935) Maintenance of General Plant	3,843,061	3,498,047
168	TOTAL Admin and General Expenses (Enter Total of lines 165-167)	102,277,651	94,800,506
169	TOTAL Elec Op and Maint Exp (Total of 80, 100, 126, 134, 141, 148, 168)	$ 615,070,551	$ 581,372,293

IDAHO ONLY

NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES

1. The data on number of employees should be reported for the payroll period ending nearest to October 31, or any payroll period ending 60 days before or after October 31.

2. If the respondent's payroll for the reporting period includes any special construction personnel, include such employees on line 3, and show the number of such special construction employees in a footnote.

3. The number of employees assignable to the electric department from joint functions of combination utilities may be determined by estimate, on the basis of employee equivalents. Show the estimated number of equivalent employees attributed to the electric department from joint functions.

1	Payroll Period Ended (Date)	December 31, 2008	December 31, 2007
2	Total Regular Full-Time Employees	2,006	1,968
3	Total Part-Time and Temporary Employees	20	29
4	Total Employees	2,026	1,997