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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UTILITIES COMMISSION

IPC-E

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 2009/Q4

Deloitte.

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

Tel: +1 208 342 9361
Fax: +1 208 342 2199
www.deloitte.com

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, 2009, 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, 2009, 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, 2009, and the results of its operations and its cash flows for the year ended December 31, 2009, 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 23, 2010

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 2009/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 Exec 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)* 04/12/2010

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)* 04/12/2010
02 Title Executive 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	04/12/2010	End of 2009/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	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
9	Statement of Income for the Year	114-117	
10	Statement of Retained Earnings for the Year	118-119	
11	Statement of Cash Flows	120-121	
12	Notes to Financial Statements	122-123	
13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	None
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	None
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	None
24	Extraordinary Property Losses	230	
25	Unrecovered Plant and Regulatory Study Costs	230	
26	Transmission Service and Generation Interconnection Study Costs	231	None
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
32	Capital Stock Expense	254	
33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Sales of Electricity by Rate Schedules	304	
44	Sales for Resale	310-311	
45	Electric Operation and Maintenance Expenses	320-323	
46	Purchased Power	326-327	
47	Transmission of Electricity for Others	328-330	
48	Transmission of Electricity by ISO/RTOs	331	None
49	Transmission of Electricity by Others	332	
50	Miscellaneous General Expenses-Electric	335	
51	Depreciation and Amortization of Electric Plant	336-337	
52	Regulatory Commission Expenses	350-351	
53	Research, Development and Demonstration Activities	352-353	
54	Distribution of Salaries and Wages	354-355	
55	Common Utility Plant and Expenses	356	None
56	Amounts included in ISO/RTO Settlement Statements	397	None
57	Purchase and Sale of Ancillary Services	398	None
58	Monthly Transmission System Peak Load	400	
59	Monthly ISO/RTO Transmission System Peak Load	400a	None
60	Electric Energy Account	401	
61	Monthly Peaks and Output	401	
62	Steam Electric Generating Plant Statistics	402-403	
63	Hydroelectric Generating Plant Statistics	406-407	
64	Pumped Storage Generating Plant Statistics	408-409	None
65	Generating Plant Statistics Pages	410-411	
66	Transmission Line Statistics Pages	422-423	

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	04/12/2010	End of 2009/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

Stockholders' Reports Check appropriate box:

[X] Two copies will be submitted

[ ] No annual report to stockholders is prepared

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/12/2010	End of 2009/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 Executive 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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/12/2010	End of 2009/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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/12/2010	End of 2009/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	04/12/2010	End of 2009/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	Executive VP, Administrative Services & CFO (4)	Darrel T. Anderson	340,000
5			
6	Sr Vice President, Power Supply (1)	James C. Miller	215,000
7			
8	Sr Vice President, General Counsel and Secretary (3)	Thomas Saldin	89,000
9			
10	Executive Vice President, Operations (4)	Dan Minor	340,000
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 and Treasurer	Steven R. Keen	215,000
19			
20	Senior Vice President , General Counsel (2)	Rex Blackburn	215,000
21			
22	Vice President and Chief Risk Officer	Lori Smith	194,000
23			
24	Senior Vice President, Power Supply (4)	Lisa Grow	220,000
25			
26	Vice President Public Affairs	Jeffrey Malmen	180,000
27			
28	Vice President, Customer Service and Regional Ops	Warren Kline	177,500
29			
30	Vice President Engineering & Operations (4)	Vern Porter	175,000
31			
32	Vice President, Audit and Compliance	Naomi Crafton-Shankel	154,000
33			
34	Corporate Secretary	Patrick Harrington	155,000
35			
36			
37	(1) Retired 8/31/2009		
38	(2) Appointed Senior VP, General Counsel 4/1/09		
39	(3) Retired 3/31/09		
40	(4) Effective 10/1/09		
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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	04/12/2010	End of 2009/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	Stephen Allred	4642 W Dawson Dr Meridian, Id 83646
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 (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/12/2010	End of 2009/Q4

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

Does the respondent have formula rates? [X] Yes [ ] No

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

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	FERC Electric Tariff First revised Volumne No. 6	FERC Docket No. ER06-787-002,003
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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	04/12/2010	End of 2009/Q4

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

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

[X] Yes
[ ] No

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

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	2009082-5128	08/28/2009	ER09-1641-000	Idaho Power Company's	FERC Electric Tariff
2				2009-2010 Annual	first revised Volumne
3				informational filing	
4				under ER09-1641	
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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	04/12/2010	End of 2009/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

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

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

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

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 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. Reclassified Non-AMI meters to allow accelerated recovery:

Idaho	$ 41,108,626	over 36 months
Oregon	2,063,431	over 18 months

New station energized 2009 - Hubbard station 230 Kv switching station - Ada County

2. None

3. None

4. None

5. Addition to existing lines:
   Line 446 Pingree to Haven 138Kv 0.8 miles of new double circuit.
   Line 446 Pingree to Haven 138Kv converted 10.9 miles of line from 46Kv to 138Kv.
   Line 525 Don - Hoku 138Kv buile 2.97 miles single circuit 138Kv.
   Line 525 Hoku - Alameda 138kv built 3.4 miles of single circuit.
   Line 723 Danskin - Hubbard 230Kv built 39.46 miles of single circuit 230Kv.

6. On March 30, 2009 IPC issued $100 millon of its 6.15% First Mortgage Bonds due April 1, 2019. Commission Authorization OPUC #4244 and IPUC IPC-E-07-19.

   On November 20, 2009 IPC issued $130 million of its 4.50% First Mortgage Bonds due March 1, 2020. Commission Authorization OPUC #4244 and IPUC IPC-E-07-19.

7. None

8. Effective 12/27/08 a 3.0% general wage increase was approved.

9. See pages 123.18 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 the major security holders in 2009. The top ten institutional shareholders list saw 4 changes from 3rd quarter to 4th quarter. In the 4th quarter First Eagle Investment Management, Blackrock Institutional Trust Company, Northern Trust Investments and Fisher investments replaced Arnhold & S. Bleichroeder Advisors LLC, Barclays Global Investors, AllianceBernstein L.P. and TIAA-CREF.

14. Idaho Power 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.

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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	4,167,328,769	4,036,452,062
3	Construction Work in Progress (107)	200-201	289,188,358	207,662,162
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		4,456,517,127	4,244,114,224
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	1,713,943,062	1,505,119,564
6	Net Utility Plant (Enter Total of line 4 less 5)		2,742,574,065	2,738,994,660
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)		2,742,574,065	2,738,994,660
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		1,335,962	786,896
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	65,015,441	60,058,187
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)		266,768	948,473
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		24,059,095	19,129,856
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		212,580	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		90,889,846	80,923,412
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		2,485,630	2,819,926
36	Special Deposits (132-134)		1,496,698	675,912
37	Working Fund (135)		39,350	41,350
38	Temporary Cash Investments (136)		19,100,000	280,000
39	Notes Receivable (141)		636,667	1,549,041
40	Customer Accounts Receivable (142)		76,792,157	64,433,173
41	Other Accounts Receivable (143)		9,087,713	6,557,937
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		1,990,343	1,723,936
43	Notes Receivable from Associated Companies (145)		18,894,101	26,579,771
44	Accounts Receivable from Assoc. Companies (146)		0	-2,011
45	Fuel Stock (151)	227	25,633,645	16,851,868
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	43,342,060	44,405,727
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/12/2010	End of 2009/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	4,711,966	5,715,442
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)		10,959,775	9,865,355
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		51,271,984	43,933,916
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		715,249	652,080
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		212,580	0
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)		262,964,072	222,635,551
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		11,520,092	14,263,910
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	715,831,853	697,644,724
73	Prelim. Survey and Investigation Charges (Electric) (183)		442,448	7,232,442
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)		523,636	486,154
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	58,492,874	63,059,804
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		15,439,928	12,841,023
82	Accumulated Deferred Income Taxes (190)	234	170,110,978	167,646,855
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		972,361,809	963,174,912
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		4,068,789,792	4,005,728,535

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	04/12/2010	end of 2009/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)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		638,757,435	618,757,435
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)	254b	2,096,925	2,096,925
11	Retained Earnings (215, 215.1, 216)	118-119	485,143,115	424,451,953
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	62,552,348	57,595,094
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)	-8,266,663	-8,706,615
16	Total Proprietary Capital (lines 2 through 15)		1,273,966,340	1,187,877,972
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,385,460,000	1,401,560,000
19	(Less) Reaquired Bonds (222)	256-257	0	166,100,000
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	28,394,091	29,457,727
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		3,060,748	3,163,279
24	Total Long-Term Debt (lines 18 through 23)		1,410,793,343	1,261,754,448
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)		3,412,806	1,965,108
29	Accumulated Provision for Pensions and Benefits (228.3)		279,806,510	253,645,884
30	Accumulated Miscellaneous Operating Provisions (228.4)		916,667	916,667
31	Accumulated Provision for Rate Refunds (229)		9,894,077	13,344,853
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)		16,239,594	12,414,695
35	Total Other Noncurrent Liabilities (lines 26 through 34)		310,269,654	282,287,207
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	112,850,000
38	Accounts Payable (232)		81,164,595	94,937,929
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		1,735,649	765,831
41	Customer Deposits (235)		464,233	311,092
42	Taxes Accrued (236)	262-263	-3,253,927	-42,412,650
43	Interest Accrued (237)		20,383,712	16,674,614
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 Resubmission	04/12/2010	end of 2009/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)		1,963,189	1,329,837
48	Miscellaneous Current and Accrued Liabilities (242)		29,912,569	37,600,238
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		280,459	2,652,850
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)		132,650,479	224,709,741
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		25,180,998	30,033,657
57	Accumulated Deferred Investment Tax Credits (255)	266-267	73,505,525	73,270,077
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	19,363,271	29,939,135
60	Other Regulatory Liabilities (254)	278	49,478,079	203,648,107
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)		664,169,740	580,306,037
64	Accum. Deferred Income Taxes-Other (283)		109,412,363	131,902,154
65	Total Deferred Credits (lines 56 through 64)		941,109,976	1,049,099,167
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		4,068,789,792	4,005,728,535

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	04/12/2010	End of 2009/Q4

STATEMENT OF INCOME

Quarterly

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

Annual or Quarterly if applicable

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

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	1,045,996,381	956,075,564		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	638,946,792	581,177,704		
5	Maintenance Expenses (402)	320-323	69,458,827	68,638,630		
6	Depreciation Expense (403)	336-337	103,587,447	96,637,583		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	7,061,068	5,482,388		
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)					
13	(Less) Regulatory Credits (407.4)			3,781,013		
14	Taxes Other Than Income Taxes (408.1)	262-263	21,069,235	19,083,954		
15	Income Taxes - Federal (409.1)	262-263	15,555,364	-1,816,783		
16	- Other (409.1)	262-263	1,547,326	-4,930,646		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	76,729,161	111,854,164		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	63,176,136	71,534,676		
19	Investment Tax Credit Adj. - Net (411.4)	266	235,447	2,269,367		
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)		297,616	504,115		
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)		870,694,192	802,542,202		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		175,302,189	153,533,362		

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

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

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
1,045,996,381	956,075,564					2
						3
638,946,792	581,177,704					4
69,458,827	68,638,630					5
103,587,447	96,637,583					6
						7
7,061,068	5,482,388					8
-22,723	-22,723					9
						10
						11
						12
	3,781,013					13
21,069,235	19,083,954					14
15,555,364	-1,816,783					15
1,547,326	-4,930,646					16
76,729,161	111,854,164					17
63,176,136	71,534,676					18
235,447	2,269,367					19
	11,632					20
						21
297,616	504,115					22
						23
						24
870,694,192	802,542,202					25
175,302,189	153,533,362					26

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	04/12/2010	End of 2009/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)		175,302,189	153,533,362		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		782,667	1,523,301		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		737,018	1,253,357		
33	Revenues From Nonutility Operations (417)		66,599	75,270		
34	(Less) Expenses of Nonutility Operations (417.1)		1,076,858	-1,567,569		
35	Nonoperating Rental Income (418)		-8,226	-14,913		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	4,957,254	4,121,080		
37	Interest and Dividend Income (419)		5,214,598	3,894,223		
38	Allowance for Other Funds Used During Construction (419.1)		7,554,922	3,141,017		
39	Miscellaneous Nonoperating Income (421)		7,178,192	608,609		
40	Gain on Disposition of Property (421.1)		122,587	3,051,506		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		24,054,717	16,714,305		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		3,973			
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		420,891	405,900		
46	Life Insurance (426.2)		-4,197,136	-381,000		
47	Penalties (426.3)		328,368	426,409		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,050,861	1,273,313		
49	Other Deductions (426.5)		5,541,928	4,817,233		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		3,148,885	6,541,855		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	34,431	31,465		
53	Income Taxes-Federal (409.2)	262-263	1,681,539	3,078,590		
54	Income Taxes-Other (409.2)	262-263	352,526	615,804		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	3,224,256	1,203,011		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	3,576,029	4,822,172		
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)		1,716,723	106,698		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		19,189,109	10,065,752		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		73,269,850	66,145,498		
63	Amort. of Debt Disc. and Expense (428)		1,225,978	1,099,817		
64	Amortization of Loss on Reaquired Debt (428.1)		776,937	707,798		
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)					
68	Other Interest Expense (431)		2,057,420	8,611,213		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		5,397,871	7,080,140		
70	Net Interest Charges (Total of lines 62 thru 69)		71,932,314	69,484,186		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		122,558,984	94,114,928		
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)		122,558,984	94,114,928		

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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) 04/12/2010	Year/Period of Report End of 2009/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		422,907,987	387,282,325
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		117,601,730	89,993,848
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	-56,910,568	(54,368,186)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-56,910,568	(54,368,186)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		483,599,149	422,907,987
	APPROPRIATED RETAINED EARNINGS (Account 215)			

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	04/12/2010	End of 2009/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
39				
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)		485,143,115	424,451,953
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		57,595,094	53,474,014
50	Equity in Earnings for Year (Credit) (Account 418.1)		4,957,254	4,121,080
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)		62,552,348	57,595,094

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	04/12/2010	End of 2009/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	122,558,984	94,114,928
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	103,587,447	96,637,583
5	Amortization of	14,290,089	12,409,124
6			
7			
8	Deferred Income Taxes (Net)	10,594,321	24,923,640
9	Investment Tax Credit Adjustment (Net)	2,842,380	1,373,356
10	Net (Increase) Decrease in Receivables	-15,306,466	-1,930,182
11	Net (Increase) Decrease in Inventory	-6,714,633	-6,435,706
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	11,916,674	-28,488,583
14	Net (Increase) Decrease in Other Regulatory Assets	47,611,061	-60,996,430
15	Net Increase (Decrease) in Other Regulatory Liabilities	10,225,050	-3,071,792
16	(Less) Allowance for Other Funds Used During Construction	7,554,923	3,141,017
17	(Less) Undistributed Earnings from Subsidiary Companies	4,957,304	4,121,080
18	Other (provide details in footnote):	-24,413,966	112,383
19			
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	264,678,714	121,386,224
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-246,539,337	-236,464,054
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	5,397,871	7,080,140
31	Other (provide details in footnote):	2,381,759	2,958,500
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-249,555,449	-240,585,694
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	2,250,259	5,784,800
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)		
45	Proceeds from Sales of Investment Securities (a)		4,100,665

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	04/12/2010	End of 2009/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	922,056	-7,449,788
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses	1,514,798	
53	Other (provide details in footnote):	-1,266,217	
54	Tax deposit withdrawal		43,926,946
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-246,134,553	-194,223,071
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	396,100,000	290,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote): Capital Infusion from IDACORP	20,000,000	37,000,000
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	416,100,000	327,000,000
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-251,063,636	-167,163,636
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):	-6,921,974	-2,150,077
77			
78	Net Decrease in Short-Term Debt (c)	-101,264,330	-32,687,145
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-56,910,568	-54,368,186
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-60,508	70,630,9[illegible]
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	18,483,653	-2,205,891
87			
88	Cash and Cash Equivalents at Beginning of Period	3,141,276	5,347,167
89			
90	Cash and Cash Equivalents at End of period	21,624,929	3,141,276

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

Amortization:

Plant	7,038,345
Regulatory assets	3,692,067
Regulatory liability	(569,074)
Unamortized debt expense	2,041,784
Unamortized discount	257,310
Water rights	1,581,118
Other	248,539
	14,290,089

Schedule Page: 120 Line No.: 13 Column: b

Per instruction Number 3 to the statement of cash flows

Cash paid during the period for:

Income taxes received from parent	16,438,944
Interest (net of amount capitalized)	66,230,730

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

Cash Flow from Operating Activities (Other)

Non-cash pension expense	4,024,783
Gain on sale of emission allowances	(297,616)
Gain on sale of non-utility property	(153,574)
Unbilled revenues	(7,338,069)
Other noncash adjustments to net income	5,833,515
Other current liabilities	(7,438,112)
Other long-term assets	1,475,491
Other long-term liabilities	(20,520,384)
	(24,413,966)

Schedule Page: 120 Line No.: 26 Column: b

Per instruction Number 4 to the statement of Cash Flows

PP&E acquired with liabilites assumed (accounts payable)	19,074,880

Schedule Page: 120 Line No.: 53 Column: b

Reinvested income from Rabbi Trust investment	(1,918,608)
Proceeds from the sale of money market investment	680,738
Miscellaneous other investing activities	(28,347)
	(1,266,217)

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	04/12/2010	End of 2009/Q4

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year	567,249			(6,723,748)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	4,159,139			414,660
3	Preceding Quarter/Year to Date Changes in Fair Value	(4,726,364)			(2,397,551)
4	Total (lines 2 and 3)	(567,225)			(1,982,891)
5	Balance of Account 219 at End of Preceding Quarter/Year	24			(8,706,639)
6	Balance of Account 219 at Beginning of Current Year	24			(8,706,639)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				542,887
8	Current Quarter/Year to Date Changes in Fair Value	1,820,148			(1,923,083)
9	Total (lines 7 and 8)	1,820,148			(1,380,196)
10	Balance of Account 219 at End of Current Quarter/Year	1,820,172			(10,086,835)

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	04/12/2010	End of 2009/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			(6,156,499)		
2			4,573,799		
3			(7,123,915)		
4			(2,550,116)	94,114,928	91,564,812
5			(8,706,615)		
6			(8,706,615)		
7			542,887		
8			(102,935)		
9			439,952	122,558,984	122,998,936
10			(8,266,663)		

NOTES TO FINANCIAL STATEMENTS

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

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Idaho Power (IPC), a wholly-owned subsidiary of IDACORP Inc., is an electric utility with a service territory covering approximately 24,000 square miles in southern Idaho and eastern Oregon. Idaho Power is regulated by the Federal Energy Regulatory Commission (FERC) and the state regulatory commissions of Idaho and Oregon. Idaho Power 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 Idaho Power.

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

Management Estimates
Management makes estimates and assumptions when preparing financial statements in conformity with GAAP. 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 Idaho Power 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
IDACORP's and Idaho Power's financial statements reflect the effects of the different ratemaking principles followed by the jurisdictions regulating Idaho Power. The application of accounting principles related to regulated operations sometimes results in Idaho Power recording expenses and revenues in a different period than when an unregulated enterprise would. In these circumstances, the amounts are deferred as regulatory assets or regulatory liabilities on the balance sheet and recorded on the income statement when recovered or returned 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 these accounting principles are discussed in more detail in Note 3.

Cash and Cash Equivalents
Cash and cash equivalents include cash on hand and highly liquid temporary investments that mature within three months of the date of acquisition.

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. All derivative instruments are recognized as either assets or liabilities at fair value on the balance sheet. Idaho Power's physical forward contracts qualify for the normal purchases and normal sales exception to derivative accounting requirements with the exception of forward contracts for the purchase of natural gas for use at Idaho Power's natural gas generation facilities. The objective of the risk management program is to mitigate the risk associated with the purchase and sale of electricity and natural gas. Because of Idaho Power's regulatory accounting mechanisms, Idaho Power records the changes in fair value of derivative instruments related to power supply as regulatory assets or liabilities.

Revenues
Operating revenues for Idaho Power related to the sale of energy are recorded when service is rendered or energy is delivered to customers. Idaho Power accrues estimated unbilled revenues for electric services delivered to customers but not yet billed at period-end. Idaho Power 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. Beginning in February 2009, Idaho Power is collecting Allowance for Funds Used During Construction (AFUDC) in base rates for a specific capital project, as discussed in Note 3, "Regulatory Matters." Cash collected under this ratemaking mechanism is recorded as a regulatory liability.

Property, Plant and Equipment and Depreciation
The cost of utility plant in service represents the original cost of contracted services, direct labor and material, 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 2.81 percent in 2009 and 2.73 percent in 2008.

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. 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 material impairments of these assets in 2008 or 2009.

Allowance for Funds Used During Construction
AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. With one exception, 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. Idaho Power's weighted-average monthly AFUDC rates for 2009 and 2008 were 6.7 percent and 5.2 percent, respectively. Idaho Power's reductions to interest expense for AFUDC were $5 million for 2009 and $7 million for 2008. Other income included $8 million and $3 million of AFUDC for 2009 and 2008, respectively.

Income Taxes
Idaho Power 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, Idaho Power'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 unless contrary to applicable income tax guidance, 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 Idaho Power's accumulated other comprehensive loss balance at December 31 (net of tax):

	2009	2008
	(thousands of dollars)	
Unrealized holding gains on available-for-sale securities	$ 1,820	$ -
Senior Management Security Plan	(10,087)	(8,707)
Total	$ (8,267)	$ (8,707)

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

New Accounting Pronouncements
In June 2009, the FASB issued amendments to prior consolidation guidance. The amendments will significantly affect the overall consolidation analysis of variable interest entities (VIEs). The amendments will require Idaho Power to reconsider their previous conclusions relating to the consolidation of VIEs, including (1) whether an entity is a VIE, (2) whether the enterprise is the VIE's primary beneficiary, and (3) what type of financial statement disclosures are required. For Idaho Power, the amendments are effective as of January 1, 2010, and early adoption is prohibited. The adoption of this guidance is not expected to have a material effect on the consolidated financial statements of Idaho Power.

Adopted Accounting Pronouncements
The FASB has issued several new accounting pronouncements. Idaho Power adopted these pronouncements in 2009:

- Effective for financial statements issued for interim and annual periods ending after September 15, 2009, The FASB Accounting Standards Codification TM became the source of authoritative U.S. GAAP recognized by the FASB to be applied to nongovernmental entities. Rules and interpretive releases of the Securities and Exchange Commission (SEC) under authority of federal securities laws are also sources of authoritative GAAP to SEC registrants. On the effective date, the Codification superseded, but did not change, all then-existing non-SEC accounting and reporting standards, and all other nongrandfathered, non-SEC accounting literature not included in the Codification became nonauthoritative. Transition to the Codification did not affect Idaho Power's results of operations, cash flows or financial positions. This Form 10-K reflects the implementation of the Codification.
- In June 2009, Idaho Power adopted guidance on accounting for and disclosures of subsequent events, events that occur after the balance sheet date but before financial statements are issued or are available to be issued. This guidance has not significantly impacted Idaho Power's consolidated financial statements.
- Fair Value Measurements: In the first quarter of 2009, Idaho Power adopted the following fair value guidance:
  - Guidelines for making fair value measurements more consistent by providing guidance related to determining fair values when there is no active market or where the price inputs being used represent distressed sales;
  - Guidance that enhances consistency in financial reporting by increasing the frequency of fair value disclosures by requiring quarterly fair value disclosures for any financial instruments that are not currently reflected on the balance sheet of companies at fair value and requires qualitative and quantitative information about fair value estimates for all such financial instruments; and
  - Guidance on other-than-temporary impairments that brings greater consistency to the timing of impairment recognition, and provides greater clarity to investors about the credit and noncredit components of impaired debt securities that are not expected to be sold. The guidance also requires increased and timelier disclosures sought by

investors regarding expected cash flows, credit losses, and the aging of securities with unrealized losses.

The adoption of this guidance did not have a material effect on Idaho Power's consolidated financial statements.

2. INCOME TAXES:

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

	2009	2008
	(thousands of dollars)	
Deferred tax assets:		
Regulatory liabilities	$ 47,183	$ 44,341
Advances for construction	8,335	9,305
Deferred compensation	17,990	17,052
Retirement benefits	84,019	85,034
Other	13,431	15,029
Total	170,958	170,761
Deferred tax liabilities:		
Property, plant and equipment	282,034	246,424
Regulatory assets	382,136	333,882
Conservation programs	4,772	1,901
PCA	34,025	62,820
Retirement benefits	65,689	69,334
Other	5,773	961
Total	774,429	715,322
Net deferred tax liabilities	$ 603,471	$ 544,561

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

	2009	2008
	(thousands of dollars)	
Computed income taxes based on statutory federal income tax rate	$ 54,296	$ 45,511
Change in taxes resulting from:		
Equity earnings of subsidiary companies	(1,735)	(1,442)
AFUDC	(4,533)	(3,577)
Capitalized interest	1,529	1,729
Investment tax credits	(3,404)	(3,490)
Repair allowance	(3,500)	(2,450)
Removal costs	(3,810)	(2,954)
Capitalized overhead costs	(3,500)	(4,200)
Uncertain tax positions	1,138	1,280
Settlement of prior years' tax returns	(4,119)	(2,761)
State income taxes, net of federal benefit	1,903	4,601
Depreciation	3,895	5,562
Other, net	(5,587)	(1,892)
Total income tax expense	$ 32,573	$ 35,917
Effective tax rate	21.0%	27.6%

The items comprising income tax expense are as follows:

		2009		2008
		(thousands of dollars)		
Income taxes currently payable (receivable):				
Federal	$	19,732	$	14,024
State		2,385		(3,602)
Total		22,117		10,422
Income taxes deferred:				
Federal		18,993		33,906
State		(5,792)		2,794
Total		13,201		36,700
Uncertain tax positions:				
Federal		(2,496)		(12,763)
State		(485)		(712)
Total		(2,981)		(13,475)
Investment tax credits:				
Deferred		3,640		5,760
Restored		(3,404)		(3,490)
Total		236		2,270
Total income tax expense	$	32,573	$	35,917

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.

Uncertain Tax Positions

Idaho Power adopted new guidance on uncertain tax positions on January 1, 2007. Idaho Power recorded an increase of $15.1 million to 2007 opening retained earnings for the cumulative effect of adopting this guidance. A reconciliation of the beginning and ending amount of unrecognized tax benefits for Idaho Power is as follows (in thousands of dollars):

		2009		2008
Balance at January 1,	$	4,119	$	17,594
Additions for tax positions of prior years		1,138		1,280
Reductions for tax positions of prior years		(4,119)		(10,426)
Settlements with taxing authorities		-		(4,329)
Balance at December 31,	$	1,138	$	4,119

If recognized, the $1.1 million balance of unrecognized tax benefits would affect the effective tax rate.

Since 2006, Idaho Power had been disputing the Internal Revenue Service's (IRS) disallowance of Idaho Power's use of the simplified service cost method (SSCM) of uniform capitalization for tax years 2001-2004. The dispute had been under review with the IRS Appeals Office.

Idaho Power recognizes interest accrued related to unrecognized tax benefits as interest expense and penalties as other expense. During the years ended December 31, 2009 and 2008, Idaho Power recognized a net reduction in interest expense of $0.2 million and $0.1 million. Idaho Power had no accrued interest as of December 31, 2009 and $0.2 million as of December 31, 2008. No penalties are accrued.

Idaho Power is subject to examination by their major tax jurisdictions – U.S. federal and state of Idaho. The open tax years are 2009 for federal and 2007-2009 for Idaho. In May 2009, Idaho Power, through its parent company, formally entered the IRS Compliance Assurance Process (CAP) program for its 2009 tax year. The CAP program provides for IRS examination throughout the year. The

2009 examination is expected to be completed in 2010. In January 2010, Idaho Power, through its parent company, was accepted into CAP for its 2010 tax year. Idaho Power is unable to predict the outcome of these examinations.

Specifically within the 2009 CAP examination, the IRS began its audit of Idaho Power's current method of uniform capitalization. In September 2009, the IRS issued Industry Director Directive #5 (IDD) which discusses the IRS's compliance priorities and audit techniques related to the allocation of mixed service costs in the uniform capitalization methods of electric utilities. The IRS and Idaho Power are jointly working through the impact the IDD guidance has on Idaho Power's uniform capitalization method. Idaho Power expects that the examination will be completed during 2010. Resolution of this matter would result in a decrease to Idaho Power's unrecognized tax benefits for its 2009 uniform capitalization deduction by $1.1 million.

3. REGULATORY MATTERS:

Regulatory Assets and Liabilities

The following is a breakdown of Idaho Power'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, 2009	2008
Regulatory Assets:					
Income taxes		$ -	$ 389,910	$ 389,910	$ 335,644
Unfunded postretirement benefits (1)		-	168,026	168,026	177,348
Pension expense deferrals (2)		-	39,251	39,251	10,583
Energy efficiency program costs (2)	2010	10,585	1,622	12,207	8,806
Power supply costs (2)	Varies (2)	84,633	-	84,633	149,099
Fixed cost adjustment (2)	2011	7,836	-	7,836	2,721
Asset retirement obligations (3)		-	14,749	14,749	10,907
Mark-to-market liabilities (4)		-	280	280	3,074
Other	2010-2015	1,914	1,875	3,789	1,224
Total (5)		$ 104,968	$ 615,713	$ 720,681	$ 699,406
Regulatory Liabilities:					
Income taxes		$ -	$ 54,958	$ 54,958	$ 46,102
Removal costs (3)		-	155,405	155,405	156,837
Investment tax credits		-	73,506	73,506	73,270
Deferred revenue-AFUDC		6,096	3,798	9,894	-
Mark-to-market assets (4)		-	715	715	652
Other	2011	479	1,100	1,579	1,818
Total (6)		$ 6,575	$ 289,482	$ 296,057	$ 278,679

(1) Represents the Idaho jurisdiction unfunded obligation of Idaho Power's pension and postretirement plans, which are discussed in note 11.

(2) These items are discussed in more detail below.

(3) Asset retirement obligations and removal costs are discussed in Note 12

(4) Mark-to market assets and liabilities are discussed in Note 15

(5) Includes $601 and $3,074 for 2009 and 2008, respectively, reported in other current assets on the balance sheets.

(6) Includes $8,972, and $2,413 for 2009 and 2008, respectively, reported in other current liabilities on the balance sheets.

In the event that recovery of Idaho Power's costs through rates becomes unlikely or uncertain, regulatory accounting would no longer apply to some or all of Idaho Power's operations and the items above may represent stranded investments. If not allowed full recovery of these items, Idaho Power would be required to write off the applicable portion, which could have a significant financial impact.

Deferred Net Power Supply Costs:
Changes in deferred power supply costs over the last two years were as follows:

	Idaho	Oregon (1)	Total
Balance at January 1, 2008	$ 92,322	$ 5,100	$ 97,422
Costs deferred through PCA and PCAM	108,688	5,196	113,884
Prior costs expensed and recovered through rates	(64,030)	(2,441)	(66,471)
SO_2 allowances credited to account	(2,184)	(175)	(2,359)
Interest and other	6,025	598	6,623
Balance at December 31, 2008	$ 140,821	$ 8,278	$ 149,099
Costs deferred through PCA and PCAM	42,533	(184)	42,349
Prior costs expensed and recovered through rates	(113,134)	(2,283)	(115,417)
SO_2 allowances credited to account	(2,034)	(83)	(2,117)
Interest and other	3,226	1,135	4,361
2007 Excess power costs order	-	6,358	6,358
Balance at December 31, 2009	**$ 71,412**	**$ 13,221**	**$ 84,633**

(1) Oregon power supply cost deferrals are subject to a statute that specifically limits rate amortizations of deferred costs to six percent of gross Oregon revenue per year (approximately $2 million). Deferrals are amortized sequentially.

<u>Idaho:</u>
Idaho Power has a PCA mechanism that provides for annual adjustments to the rates charged to its Idaho retail customers. The PCA tracks Idaho Power's actual net power supply costs (primarily 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.

The following table summarizes the PCA adjustments during the last three years:

Effective Date	$ Change (millions)	Notes
June 1, 2009	$84.3	The IPUC's order reflects revised methodology discussed below in "PCA Workshops." The increase was net of $4.5 million of gains from sales of excess SO_2emission allowances which the IPUC ordered be applied against the PCA. The IPUC has allowed Idaho Power to retain its PCA sharing percentage of the gain from sales of excess SO_2 allowances as a shareholder benefit with the remainder recorded as a customer benefit, substantially all of which was used to reduce the PCA. Proceeds from the sale of renewable energy certificates (RECs) will also be used to reduce the PCA. RECs are acquired by Idaho Power through purchases of renewable energy.
June 1, 2008	73.3	Increase was net of $16.5 million of gains from sales of excess SO2emission allowances

June 1, 2007	77.5	Increase was net of $69.1 million of gains from sales of excess SO2 emission allowances

PCA Workshops: In its order approving Idaho Power's 2008-2009 PCA, the IPUC directed Idaho Power to set up workshops with the IPUC Staff and several of Idaho Power's largest customers to address issues not resolved in that PCA filing. The workshops resulted in the following changes to the PCA mechanism, effective February 1, 2009:

- PCA sharing ratio – the PCA allocates the deviations in net power supply expenses between customers (95 percent) and shareholders (5 percent). The previous sharing ratio was 90/10.
- LGAR – the LGAR is an element of the PCA formula that is intended to eliminate recovery of power supply expenses associated with load growth resulting from changing weather conditions, a growing customer base, or changing customer use patterns. The 2007 general rate case reset the LGAR from $29.41 to $62.79 per MWh, but applied that rate to only 50 percent of the load growth beginning in March 2008. The stipulation agreed on a new formula for calculating the LGAR. Based on the final rates approved by the IPUC in the 2008 general rate case and the supporting data, the current LGAR is $26.63 per MWh, effective February 1, 2009.
- Use of Idaho Power's operation plan power supply cost forecast – the operation plan forecast may better match current collections with actual net power supply costs in the year they are incurred and result in smaller amounts being included in the following year's "true-up" rate, beginning with the 2009-2010 PCA filing.
- Inclusion of third-party transmission expense – transmission expenses paid to third parties to facilitate wholesale purchases and sales of energy, including losses, are a necessary component of net power supply costs. Deviation in these costs from levels included in base rates is now reflected in PCA computations.
- Adjusted distribution of base net power supply costs – base net power supply costs are distributed throughout the year based upon the monthly shape of normalized revenues for purposes of the PCA deferral calculation.

Oregon

2006-2007 Excess Power Costs: In December 2007, the OPUC approved the deferral for future recovery of $2 million of excess power costs incurred from May 1, 2006, through April 30, 2007, and effective September 2009, these costs began being collected through rates and amortized. Idaho Power expects amortization of this deferral to be completed in December 2010.

May-December 2007 Excess Power Costs: In May 2009, the OPUC approved the deferral for future recovery of $6.4 million, including interest through the date of the order, of excess net power supply costs incurred from May-December 2007. Idaho Power recorded the $6.4 million deferral in the second quarter 2009 as a reduction to power cost adjustment expense. The amount to be recovered was reduced by $0.9 million of previously deferred emission allowance sales (including interest) during the same period.

Oregon Power Supply Cost Mechanism: Idaho Power's power cost recovery mechanism in Oregon went into effect in 2008. It has two components: the annual power cost update (APCU) and the power cost adjustment mechanism (PCAM). The combination of the APCU and the PCAM allows Idaho Power to recover excess net power supply costs in a more timely fashion than through the previously existing deferral process.

The APCU allows Idaho Power 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," Idaho Power's calculation of estimated normalized net power supply expenses for the following April through March test period, and the "March Forecast," Idaho Power's forecast of 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. New base rates are implemented each June 1 based on the APCU.

2010 APCU: Idaho Power's October Update portion of the 2010 APCU indicates that revenues associated with Idaho Power's base net power supply costs would be increased by $2.6 million over the current APCU, an average 8.2 percent increase. The actual impact will be determined once the March Forecast portion is filed in March 2010 and combined with the October Update. Final rates are expected to become effective on June 1, 2010.

2009 APCU: A rate increase of 11.5 percent, or $3.9 million annually, took effect June 1, 2009.

2008 APCU: A rate increase of 15.7 percent, or $4.8 million annually, took effect June 1, 2008.

The PCAM is a true-up 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, Idaho Power 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 Idaho Power 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 Idaho Power. However, collection by Idaho Power will occur only to the extent that it results in Idaho Power's actual return on equity (ROE) for the year being no greater than 100 basis points below Idaho Power's last authorized ROE. A refund to customers will occur only to the extent that it results in Idaho Power's actual ROE for that year being no less than 100 basis points above Idaho Power's last authorized ROE.

2009 PCAM: Actual net power supply costs were within the deadband, resulting in no deferral.
2008 PCAM: Actual net power supply costs exceeded the forecast for the 2008 calendar year by $7.7 million and, after application of the deadband, resulted in a $5.1 million deferral in 2008. The OPUC approved deferral of this amount in January 2010, to be amortized sequentially after previously authorized deferrals.

Fixed Cost Adjustment Mechanism (FCA)
The FCA mechanism began as a pilot program for Idaho Power's Idaho residential and small general service customers, running from 2007 through 2009. The FCA is a rate mechanism designed to remove Idaho Power'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. On October 1, 2009, Idaho Power filed an application with the IPUC to make the FCA mechanism permanent beginning January 1, 2010. The application is being processed under modified procedure.

Idaho Power accrued $6.6 million related to the FCA in 2009; subject to IPUC approval, recovery should begin June 1, 2010. The IPUC approved a rate increase effective June 1, 2009, through May 31, 2010, to recover $2.7 million of fixed costs under-recovered during 2008. In 2008, the IPUC approved a rate reduction, effective June 1, 2008 through May 31, 2009, to return $2.4 million of fixed costs over-recovered in 2007.

Idaho Rate Cases
2009 Settlement Agreement: On January 13, 2010, the IPUC approved a settlement agreement among Idaho Power, several of Idaho Power's customers, the IPUC staff and others. Significant elements of the settlement agreement include:

- A general rate moratorium in effect until January 1, 2012. The moratorium does not apply to other specified revenue requirement proceedings, such as the PCA, the FCA, pension funding, AMI, energy efficiency rider, and government imposed fees.
- A specified distribution of the expected 2010 PCA. This distribution is intended to reduce customer rates, provide some general rate relief to Idaho Power and reset base power supply costs for the PCA. The associated rate change is expected to become effective June 1, 2010. This provision is in anticipation of a significant reduction in PCA rates for the 2010-2011 PCA year. The PCA reduction will be allocated as follows:
  - The first $40 million will be allocated equally between customers and Idaho Power. Idaho Power's share would be applied to increase permanent base rates on a uniform percentage basis to all customer classes and contract customers. The customers' share would be a direct rate reduction through the PCA.
  - All of the next $20 million will be allocated to customers as a direct rate reduction through the PCA.
  - PCA reductions in excess of $60 million will be applied to absorb any increase in the base level of net power supply expenses.
  - If the PCA reduction exceeds $60 million plus the increase in base net power supply expenses, the next $10 million will be allocated equally between Idaho Power and customers in the same manner as the first $40 million.
  - Any remainder will go entirely to customers.
- A provision to share earnings with customers if Idaho Power's actual rate of return on equity is more than 10.5 percent in any calendar year from 2009 to 2011 in its Idaho jurisdiction. Idaho Power will share with Idaho customers 50 percent of any profits in excess of 10.5 percent.
- A provision to allow the accelerated amortization of accumulated deferred investment tax credits (ADITC) if Idaho Power's

actual rate of return on equity is below 9.5 percent in any calendar year from 2009 to 2011 in its Idaho jurisdiction. Idaho Power would be permitted to amortize additional ADITC in an amount up to $45 million over the three-year period, but could use no more that $15 million in any one year unless there is a carryover. Carryover amounts are added to the $15 million annual allowance up to a maximum amortization of $25 million in any one year.

Because Idaho Power's Idaho-jurisdiction return on equity was between 9.5 and 10.5 percent, the sharing and accelerated amortization provisions were not triggered in 2009.

The settlement agreement also included a provision to reestablish the base level for net power supply costs effective with the June 1, 2010 PCA rate change. On January 19, 2010, Idaho Power filed with the IPUC a request to increase base net power supply costs by $74.8 million in the Idaho jurisdiction. This amount, which is subject to approval by the IPUC, reflects the maximum increase to Idaho Power's base net power supply costs, which would be used for both base rates and PCA calculations. The actual change in net power supply costs for rate purposes will depend upon the amount approved by the IPUC as well as the amount of any PCA decrease determined for the 2010-2011 PCA year. Written comments or protests with respect to Idaho Power's application are due March 11, 2010.

Idaho 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, Idaho Power filed a request for reconsideration with the IPUC and on March 19, 2009, the IPUC issued an order that increased Idaho Power's Idaho revenue requirement by an additional $6.1 million to approximately $27 million for this rate case, raising the average rate increase from 3.1 percent to 4.0 percent.

The January 30, 2009 order authorized approximately $15 million related to increases in base net power supply costs. It also allowed Idaho Power to include in rates approximately $6.8 million ($10.6 million including income tax gross-up) of 2009 AFUDC relating to the Hells Canyon Complex relicensing project. Typically, AFUDC is not included in rates until a project is in use and benefitting customers, but the IPUC determined that including this amount in current rates is in the public interest. Because AFUDC is already recorded on an accrual basis, this portion of the rate increase will improve cash flows but will not have a current impact on Idaho Power's net income. The amounts collected are being deferred as a regulatory liability and will be recognized in revenues over the life of the new license once it has been issued.

The IPUC denied reconsideration with respect to a refund of $3.3 million of fees recovered by Idaho Power from the FERC. On April 2, 2009, Idaho Power filed an application with the IPUC for an accounting order approving amortization of the fees over a five-year period beginning October 2006 when Idaho Power received the FERC credit. The IPUC approved Idaho Power's requested amortization period in an order issued on April 28, 2009. In the first quarter of 2009, Idaho Power recorded a charge of approximately $1.7 million to electric utility other operations expense and a corresponding regulatory liability for the amount to be refunded from February 1, 2009, through the end of the amortization period, September 2011. As the regulatory liability is amortized it will reduce electric utility other operations expense ratably over the remaining amortization period.

Idaho 2007 General Rate Case: 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 May 30, 2008, the IPUC authorized Idaho Power 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. Danskin CT1 located near Mountain Home, Idaho, began commercial operations on March 11, 2008.

Oregon 2009 General Rate Case: On December 16, 2009, Idaho Power filed a Joint Stipulation and testimony in support of a stipulation that would settle the revenue requirement issues surrounding the general rate case filed on July 31, 2009. If approved by the OPUC, the Joint Stipulation would increase base rates $5 million, or 15.4 percent, based on a return on equity of 10.175 percent and an overall rate of return of 8.061 percent. The requested effective date is March 1, 2010.

Advanced Metering Infrastructure (AMI)

The AMI project provides the means to automatically retrieve energy consumption information, eliminating manual meter reading expense. Idaho Power intends to install this technology for approximately 99 percent of its customers and is on pace to complete the installations by the end of 2011.

Idaho: On February 12, 2009, the IPUC approved Idaho Power's application requesting a Certificate of Public Convenience and Necessity for the deployment of AMI technology and approval of accelerated depreciation for the existing metering equipment. The IPUC subsequently clarified that Idaho Power can expect in the ordinary course of events, to include in rate base the prudent capital costs of deploying AMI as it is placed in service up to the capital cost commitment estimate of $70.9 million. The IPUC also clarified, as requested by Idaho Power, that it does not anticipate that the immediate savings derived from the implementation of AMI throughout Idaho Power's service territory will eliminate or wholly offset the increase in Idaho Power's revenue requirement caused by the authorized depreciation period.

On May 29, 2009, the IPUC approved annual recovery of $10.5 million, effective June 1, 2009. The order was based on Idaho Power's actual investment in AMI to date, annualized through December 31, 2009. The IPUC also allowed Idaho Power to begin three-year accelerated depreciation of the existing metering equipment on June 1, 2009. The order reflects annualized depreciation expense relating to AMI of $9.2 million. Actual depreciation expense recorded over the last seven months of 2009 totaled $6.2 million.

Oregon: The OPUC approved accelerated depreciation and recovery of existing meters in the Oregon jurisdiction over an 18-month period beginning January 2009. Idaho Power's AMI deployment schedule calls for the replacement of the Oregon service-territory meters around October 2010. The existing meters will be fully depreciated prior to their removal from service. The approval increased both rates and depreciation expense $0.8 million in 2009.

Depreciation Filings

In 2008 and 2009 Idaho Power filed revisions to its depreciation rates with the IPUC, OPUC and FERC. The commissions approved the new rates, which reduce depreciation expense approximately $8.5 million annually. Idaho Power began applying the new depreciation rates in August 2008.

OATT

Formula Rates: In 2006, Idaho Power moved from a fixed rate to a formula rate, which allows transmission rates to be updated annually based on financial and operational data Idaho Power files with the FERC. The FERC accepted Idaho Power's initial formula rates effective June 1, 2006, subject to refund pending the outcome of a hearing and settlement process.

Idaho Power and the parties who had opposed the filing entered into a settlement agreement, which was approved by the FERC in August 2007. The settlement agreement reduced Idaho Power's formula rates, established an authorized rate of return on equity of 10.7 percent and resulted in a $1.7 million refund by Idaho Power. The settlement agreement did not cover the treatment of "Legacy Agreements", which were contracts for transmission service that contained their own terms, conditions and rates and were in existence before implementation of the OATT in 1996.

On January 15, 2009, the FERC issued an order that required Idaho Power to reduce its transmission service rates to FERC jurisdictional customers and refund $13.3 million to these customers. Based on the FERC order, Idaho Power reserved an additional $7.9 million (including $0.7 million of interest) in 2008 to bring its reserve to the $13.3 million ordered refunded. Idaho Power made the refunds in February 2009 and filed a request for rehearing with the FERC. Of the additional $7.9 million ordered refunded, $2.3 million related to transmission revenues recorded in 2007 and $1.7 million related to transmission revenues recorded in 2006. In March 2009, the FERC issued a tolling order that effectively relieved it from acting for an indefinite period of time on Idaho Power's request for rehearing. Idaho Power cannot predict when the FERC will rule on its request for rehearing or the outcome of this matter.

As discussed below, Idaho Power received an accounting order from the IPUC on October 30, 2009, authorizing it to defer for potential future recovery approximately $4.7 million in unrecovered transmission-related revenues associated with the FERC order.

2009 OATT: On August 28, 2009, Idaho Power filed its informational filing with the FERC that contains the annual update of the formula rate based on the 2008 test year. The new rate included in the filing was $15.83 per kW-year, an increase of $2.02 per kW-year, or 14.6 percent. New rates were effective October 1, 2009.

2008 OATT: On August 28, 2008, Idaho Power filed its informational filing with the FERC that contained the annual update of the formula rate based on the 2007 test year. The rate included in the filing was $18.88 per kW-year, a decrease of $0.85 per kW-year, or 4.3 percent. New rates were effective October 1, 2008. Idaho Power subsequently adjusted its rates to $13.81 per kW-year in compliance with a January 15, 2009, order.

Legacy Agreements: Subsequent to the January 15, 2009, FERC Order, Idaho Power has sought to mitigate the resulting revenue shortfall by revising certain of the Legacy Agreements as provided for in the agreements.

The Restated Transmission Services Agreement and three long-term service agreements with PacifiCorp were amended to replace a portion of the services provided for in the agreement with OATT service, effective June 13, 2009. As calculated in the FERC filings, the estimated net transmission revenue increase for the period June 13, 2009 through June 12, 2010 is approximately $3.2 million. These amendments are expected to increase 2010 transmission revenue $1.3 million as compared to 2009.

Idaho Power also filed a request with the FERC on June 19, 2009, for an increase in rates for the Agreement for Interconnection and Transmission Services with PacifiCorp. As calculated in the filing, the estimated net transmission revenue increase for the period September 1, 2009 through August 31, 2010, would be approximately $3.7 million. PacifiCorp has intervened in this case. Idaho Power began collecting the new rates effective August 19, 2009, subject to refund pending settlement procedures and hearing. Settlement discussions are ongoing. This revision is expected to increase 2010 transmission revenue $2.5 million as compared to 2009.

OATT Shortfall Filing
For Idaho jurisdictional revenue requirement determinations, revenues from third parties (non-state jurisdictional) received through the OATT, referred to as revenue credits, are a direct offset to Idaho Power's overall revenue requirement. In the last two general rate cases, Idaho Power included an estimate of OATT revenues from third parties based on the forecasted OATT rate. However, as discussed above in "OATT", a FERC order issued on January 15, 2009, significantly reduced actual third-party transmission revenues Idaho Power received from June 2006 to date, resulting in an overstatement of the revenue credits in the Idaho jurisdictional revenue requirement.

On October 30, 2009, the IPUC approved an Idaho Power request for authorization to defer the difference between the revenue credits in the last two general rate cases and the amount of OATT revenues Idaho Power has received since March 2008 and expects to receive through May 2010. The IPUC order authorizes Idaho Power to amortize the unrecovered transmission revenues on a straight-line basis over a three-year period beginning January 1, 2011 and did not authorize a carrying charge on the balance. Based on actual and projected transmission revenues from March 2008 through May 2010, Idaho Power recorded a $4.7 million regulatory asset in 2009 for potential future recovery.

Idaho Power has filed a request for rehearing of the FERC order and is taking additional measures to address the revenue shortfall. If the FERC issues are resolved in Idaho Power's favor, Idaho Power will reduce the deferral.

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 June 1, 2007, the IPUC issued an order authorizing Idaho Power to account for its defined benefit pension expense on a cash basis, and to defer and account for pension expense as a regulatory asset. On February 17, 2010, the IPUC approved a recovery methodology that would permit Idaho Power to include in future rate cases a reasonable amortization and recovery of cash contributions. Idaho Power deferred approximately $29 million, $8 million and $3 million of pension expense to a regulatory asset in 2009, 2008, and 2007 respectively. Deferred pension costs are expected to be amortized to expense to match the revenues received when future pension contributions are recovered through rates. Idaho Power does not receive a carrying charge on the current deferral balance. A carrying charge will be recorded on the difference between actual cash contributions and the recovery of those amounts in rates.

Idaho Energy Efficiency Rider (Rider)
Idaho Power's Rider is the chief funding mechanism for Idaho Power's investment in energy efficiency, conservation, and demand response programs. Effective June 1, 2009, Idaho Power collects 4.75 percent of base revenues, or approximately $29-$33 million annually, under the Rider. Idaho Power collected 2.5 percent of base revenues from June 2008-May 2009 and 1.5 percent prior to

June 2008. Energy efficiency program expenditures are reported as an operating expense with an equal amount of revenues recorded in other revenues, resulting in no net impact on earnings. The cumulative variance between expenditures and amounts collected through the rider is recorded as a regulatory asset or liability pending future collection from or obligation to customers. An asset balance indicates that Idaho Power has spent more than collected and a liability balance indicates that Idaho Power has collected more than it has spent. At December 31, 2009, Idaho Power's rider balance was a regulatory asset of $11 million.

In the 2008 general rate case, Idaho Power requested that the IPUC explicitly find that Idaho Power's expenditures between 2002 and 2007 of $29 million of funds obtained from the Rider were prudently incurred and no longer subject to potential disallowance. In 2009, the IPUC approved a stipulation identifying $14.3 million of Rider funding as prudent, and on January 25, 2010, Idaho Power and the IPUC staff filed a stipulation for approval by the IPUC to find the remaining expenditures through 2007 were prudently incurred.

On October 5, 2009, Idaho Power and other investor-owned electric utilities serving in Idaho began a series of many informal public workshops with the IPUC Staff to discuss how energy efficiency evaluation and prudency will be determined on a prospective basis. As a result, a Memorandum of Understanding written by Staff, Idaho Power and other investor-owned electric utilities in Idaho has been signed outlining a process for future energy efficiency expenditure approval. This document was filed with the IPUC on January 25, 2010.

4. LONG-TERM DEBT

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

	2009	2008
	(thousands of dollars)	
First mortgage bonds:	$	$
7.20% Series due 2009	-	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	120,000
6.15% Series due 2019	100,000	-
4.50% Series due 2020	130,000	-
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	1,215,000	1,065,000
Pollution control revenue bonds:		
Variable Rate Series 2003 due 2024(1)	-	49,800
Variable Rate Series 2006 due 2026(1)	-	116,300
5.15% Series due 2024(1)	49,800	-
5.25% Series due 2026(1)	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	8,509	9,573
Unamortized discount - net	(3,060)	(3,163)
Term Loan Credit Facility	-	166,100
Purchase of pollution control revenue bonds	-	(166,100)

Total Idaho Power outstanding debt(2)	$	1,410,794	$	1,261,755

(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, 2009, to $1.381 billion.

(2) At December 31, 2009 and 2008, the overall effective cost of Idaho Power's outstanding debt was 5.76 percent and 5.59 percent, respectively.

At December 31, 2009, the maturities for the aggregate amount of long-term debt outstanding were (in thousands of dollars):

2010	2011	2012	2013	2014	Thereafter
$ 1,064	$ 121,064	$ 101,064	$ 71,064	$ 1,064	$ 1,118,534

Long-Term Financing
On March 30, 2009, Idaho Power issued $100 million of its 6.15% first mortgage bonds, due April 1, 2019. On November 20, 2009, Idaho Power issued $130 million of its 4.5% first mortgage bonds, due March 1, 2020. Idaho Power used the net proceeds from the two bond issuances to repay short-term debt and to repay $80 million of its 7.20 % first mortgage bonds that matured on December 1, 2009. As of December 31, 2009, Idaho Power had issued all securities remaining registered under its shelf registration statement.

Mortgage: As of December 31, 2009, Idaho Power could issue under the mortgage approximately $431 million of additional first mortgage bonds based on total unfunded property additions of approximately $719 million. Idaho Power could issue an additional $612 million of first mortgage bonds based on retired first mortgage bonds. These amounts are further limited by the maximum amount of first mortgage bonds set forth in the mortgage discussed below.

The mortgage secures all bonds issued under the indenture equally and ratably, without preference, priority or distinction. First mortgage bonds issued in the future will also be secured by the mortgage. The lien of the indenture constitutes a first mortgage on all the properties of Idaho Power, 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 Idaho Power 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 Idaho Power 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 Idaho Power. The mortgage requires Idaho Power to spend or appropriate 15 percent of its annual gross operating revenues for maintenance, retirement or amortization of its properties. Idaho Power may, however, anticipate or make up these expenditures or appropriations within the five years that immediately follow or precede a particular year.

On February 17, 2010, Idaho Power entered into the Forty-fifth Supplemental Indenture, dated as of February 1, 2010, to the Indenture of Mortgage and Deed of Trust, dated as of October 1, 1937, between Idaho Power and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company) and R.G. Page, as Trustees (Stanley Burg, successor individual trustee) for the purpose of increasing the maximum amount of first mortgage bonds issuable by Idaho Power from $1.5 to $2.0 billion. The amount issuable is also restricted by property, earnings and other provisions of the mortgage and supplemental indentures to the mortgage. Idaho Power may amend the indenture and increase this amount without consent of the holders of the first mortgage bonds. The indenture requires that Idaho Power'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 Idaho Power 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.

Pollution Control Revenue Refunding Bonds and Term Loan Credit Agreement: On April 3, 2008, Idaho Power made a mandatory purchase of two series of Pollution Control Revenue Refunding Bonds issued for the benefit of Idaho Power, the $116.3

million aggregate principal amount of Pollution Control Revenue Refunding Bonds Series 2006 issued by Sweetwater County, Wyoming due 2026 and the $49.8 million aggregate principal amount of Pollution Control Revenue Refunding Bonds Series 2003 issued by Humboldt County, Nevada due 2024 (together the Pollution Control Bonds). Idaho Power 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. This change was made to mitigate the higher-than-anticipated interest costs in the auction mode, which was a result of the financial guarantor's credit ratings deterioration.

On August 20, 2009, J.P. Morgan Securities Inc. as the Remarketing Agent, purchased the Pollution Control Bonds from Idaho Power for remarketing to the public. The Humboldt County Bonds carry a 5.15 percent term interest rate and mature on December 1, 2024. The Sweetwater County Bonds carry a 5.25 percent term interest rate and mature on July 15, 2026. The Pollution Control Bonds are not subject to redemption for 10 years, except for extraordinary optional and mandatory redemption prior to maturity, in each case at 100 percent of the principal amount, plus accrued interest if any to the date of redemption. In connection with the remarketing of the Pollution Control Bonds, the financial guaranty insurance policies securing the Pollution Control Bonds were terminated.

On August 25, 2009, Idaho Power used proceeds from the reoffering of the Pollution Control Bonds and additional corporate funds to prepay its $170 million loan under a Term Loan Credit Agreement dated as of February 4, 2009, among 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.

5. NOTES PAYABLE:

Idaho Power has a $300 million credit facility each of which 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, 2009, Idaho Power had regulatory authority to incur up to $450 million of short-term indebtedness.

At December 31, 2009, no loans were outstanding on Idaho Power's facilities. Balances and interest rates of Idaho Power's short-term borrowings were as follows at December 31 (in thousands of dollars):

	2009	2008
	(thousands of dollars)	
Balances:		
At the end of year	$ -	$ 112,850
Average during the year	$ 46,386	$ 151,192
Weighted-average interest rate:		
At the end of year	-	4.89%

6. COMMON STOCK

In 2009 and 2008, IDACORP contributed $20 million and $37 million respectively, of additional equity to Idaho Power. No additional shares of Idaho Power common stock were issued.

Idaho Power's articles of incorporation contain restrictions on the payment of dividends on its common stock if preferred stock dividends are in arrears. Idaho Power has no preferred stock outstanding.

Idaho Power must obtain approval of the OPUC before it could directly or indirectly loan funds or issue notes or give credit on its books to IDACORP.

7. STOCK-BASED COMPENSATION

Through its parent company IDACORP, Idaho Power 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, restricted stock, performance shares, and several other types of stock-based awards. The RSP permits only the grant of restricted stock or performance-based restricted stock. At December 31, 2009, the maximum number of shares available under the LTICP and RSP were 1,602,259 and 25,515, respectively.

Stock awards: Restricted stock awards have three-year vesting periods and entitle the recipients to dividends and voting rights. Unvested shares are restricted as to disposition and subject to forfeiture under certain circumstances. The fair value of these awards is based on the market price of common stock on grant date and is charged to compensation expense over the vesting period, based on the number of shares expected to vest.

Performance-based restricted stock awards have three-year vesting periods and entitle the recipients to voting rights. Unvested shares are restricted as 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. Dividends are accrued and paid out only on shares that eventually vest.

The performance awards 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. Idaho Power share amounts represent the portion of IDACORP amounts related to Idaho Power employees:

	Number of Shares	Weighted-Average Grant Date Fair Value
Nonvested shares at January 1, 2009	303,257	$ 26.68
Shares granted	144,143	21.49
Shares forfeited	(27,158)	23.43
Shares vested	(134,207)	26.42
Nonvested shares at December 31, 2009	286,035	$ 24.49

The total fair value of shares vested during the years ended December 31, 2009 and 2008 was $3.9 million and $0.8 million, respectively. At December 31, 2009, IDACORP had $3.6 million of total unrecognized compensation cost related to nonvested share-based compensation that was expected to vest. Idaho Power's share of this amount was $3.4 million. These costs are expected to be recognized over a weighted-average period of 1.67 years. Idaho Power uses IDACORP's 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 following table presents information about options granted and exercised (in thousands of dollars, except for weighted-average amounts):

	2009	2008
Fair value of options vested	$ 208	$ 353

Intrinsic value of options exercised	204	182
Cash received from exercises	591	707
Tax benefits realized from exercises	80	71

As of December 31, 2009, Idaho Power had recognized all compensation cost related to stock options. Idaho Power uses IDACORP's uses original issue and/or treasury shares to satisfy exercised options.

Idaho Power's stock option transactions in IDACORP are summarized below. Idaho Power share amounts represent the portion of IDACORP amounts related to Idaho Power employees:

	Number of Shares	Weighted-Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value (000s)
Outstanding at December 31, 2008	576,996	$ 34.34	3.67	$ 611
Exercised	(25,800)	22.92		
Forfeited	(3,632)	29.75		
Expired	(133,600)	39.86		
Outstanding at December 31, 2009	413,964	$ 33.31	2.96	$ 862
Vested or expected to vest at December 31, 2009	413,932	$ 33.31	2.96	$ 862
Exercisable at December 31, 2009	397,903	$ 33.45	2.87	$ 826

Compensation Expense: 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 Idaho Power for those costs associated with Idaho Power's employees (in thousands of dollars):

	2009	2008
Compensation cost	$ 3,986	$ 3,683
Income tax benefit	$ 1,587	$ 1,440

No equity compensation costs have been capitalized.

8. COMMITMENTS:

Purchase Obligations:
At December 31, 2009, Idaho Power had the following long-term commitments relating to purchases of energy, capacity, transmission rights and fuel:

	2010	2011	2012	2013	2014	Thereafter
	(thousands of dollars)					
Cogeneration and power production	$ 210,999	$ 229,740	$ 124,051	$ 113,884	$ 114,850	$ 1,680,001
Power and transmission rights	44,298	21,979	8,699	3,296	2,404	7,612
Fuel	64,132	64,130	52,671	54,032	53,136	95,346

As of December 31, 2009, Idaho Power had signed agreements to purchase energy from 96 CSPP facilities with contracts ranging from one to 30 years. Eighty of these facilities, with a combined nameplate capacity of 298 MW, were on-line at the end of 2009; the other 16 facilities under contract, with a combined nameplate capacity of 266 MW, are projected to come on-line during 2010 and 2011. The majority of the new facilities will be wind resources which will generate on an intermittent basis. During 2009, Idaho Power purchased 970,419 megawatt-hours (MWh) from these projects at a cost of $59 million, resulting in a blended price of 6.1 cents per kilowatt hour. Idaho Power purchased 756,014 megawatt-hours at a cost of $45.9 million in 2008.

Guarantees
Idaho Power has agreed to guarantee the performance of reclamation activities at Bridger Coal Company of which IERCo owns a one-third interest. This guarantee, which is renewed each December, was $63 million at December 31, 2009. Bridger Coal Company has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. At this time Bridger Coal Company is revising their estimate of future reclamation costs. To ensure that the reclamation trust fund maintains adequate reserves, Bridger Coal Company has the ability to add a per ton surcharge if it is determined that future liabilities exceed the trust's assets. Because of the existence of the fund and the ability to apply a per ton surcharge, the estimated fair value of this guarantee is minimal.

9. CONTINGENCIES

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 or other forms of relief. 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. Decisions in these appeals may have implications with respect to other pending cases, including those to which Idaho Power or IE, another wholly-owned subsidiary of IDACORP, are parties. Idaho Power and IE intend to vigorously defend their positions in these proceedings, but are unable to predict the outcome of these matters. Except as to the matters described below under "Pacific Northwest Refund," Idaho Power and IE believe that settlement releases they have obtained that are described below under "California Refund" and "Market Manipulation" will restrict potential claims that might result from the disposition of the pending Ninth Circuit review petitions and that these matters will not have a material adverse effect 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. The FERC has issued numerous orders establishing price mitigation plans for sales in the California wholesale electricity market, including the methodology for determining refunds. IE and numerous other parties have 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 before the Ninth Circuit, which from time to time has identified discrete cases that can proceed to briefing and decision while it stayed action on the other consolidated cases.

On May 22, 2006 the FERC approved an Offer of Settlement between and among IE and Idaho Power, 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) and additional parties that elected to be bound by the settlement. The settlement disposed of matters encompassed by the California refund proceeding, as well as other claims and investigations relating to the western energy situation among and between the parties agreeing to be bound by it. Although many market participants agreed to be bound by the settlement, other market participants, representing a small minority of potential refund claims, initially elected not to be bound by the settlement. From time to time, as the California Parties have reached settlements with those other market participants, they have elected to opt into the IE-Idaho Power-California Parties' settlement. The settlement provided for approximately $23.7 million of IE's and Idaho Power's estimated $36 million rights to accounts receivable from the Cal ISO and the California Power Exchange (CalPX) to be assigned to an escrow account for refunds and for an additional $1.5 million of accounts receivable to be retained by the CalPX until the conclusion of the litigation. The additional $1.5 million of accounts receivable retained by the CalPX is available to fund the claims of non-settling parties if they prevail in the remaining litigation of these California market matters. Any additional amounts owed to non-settling parties would be funded by other amounts owed to IE and Idaho Power by the Cal ISO and CalPX, or directly by IE and Idaho Power, and any excess funds remaining at the end of the case would be returned to IE and Idaho Power. The remaining IE and Idaho Power receivables were paid to IE and Idaho Power under the settlement.

In an August 2006 decision, the Ninth Circuit ruled that all transactions that occurred within the CalPX and the Cal ISO markets were proper subjects of the refund proceeding. In that decision the Ninth Circuit refused to expand the proceedings into the bilateral market, approved the refund effective date as October 2, 2000, 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. Parts of the decision exposed sellers to increased claims for potential refunds. The Ninth Circuit issued its mandate on April 15, 2009, thereby officially returning the cases to the FERC for further action consistent with the court's decision.

On November 19, 2009, the FERC issued an order to implement the Ninth Circuit's remand. The remand order established a trial-type hearing in which participants will be permitted to submit information regarding (i) specified tariff violations committed by any public utility seller from January 1, 2000 - October 2, 2000 resulting in a transaction that set a market clearing price for the trading period when the violation occurred and (ii) claims for refunds for multi-day transactions and energy exchange transactions entered into during the refund period (October 2, 2000 – June 20, 2001). Numerous parties including IE and Idaho Power filed motions to clarify the FERC's order. Although IE and Idaho Power are unable to predict when or how FERC will rule on these motions, the effect of the remand order for IE and Idaho Power is confined to the minority of market participants that are not bound by the IE-Idaho Power-California Parties' settlement described above. Accordingly, IE and Idaho Power believe the remanded proceedings will not have a material adverse effect on their consolidated financial positions, results of operations or cash flows.

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 Idaho Power made such a cost filing, which was rejected by the FERC. On June 18, 2009, FERC issued an order stating that it was not ruling on IE's and Idaho Power's request for rehearing of the cost filing rejection because their request had been withdrawn in connection with the IE-Idaho Power-California Parties' settlement. On July 8, 2009 IE and Idaho Power sought further rehearing at the FERC because their withdrawal pertained only to the parties with whom IE and Idaho Power had settled. On June 18, 2009, in a separate order, the FERC ruled that only net refund recipients were responsible for the costs associated with cost filings. While most net refund recipients are bound by the settlement, until the Cal ISO completes its refund calculations, it is uncertain whether there are any net refund recipients who are not bound by the settlement If there are no such parties, then IE's and Idaho Power's request for rehearing will be moot. FERC has not yet ruled on the request for rehearing. IE and Idaho Power are unable to predict how or when the FERC might rule, but the effect of any such ruling is confined to obligations of IE and Idaho Power to the small minority of claims of market participants that are not bound by the settlement. Accordingly, IE and Idaho Power believe this matter will not have a material adverse effect on their consolidated financial positions, results of operations or cash flows.

Market Manipulation: 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 Idaho Power, 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 Idaho Power. Later in 2004, the FERC approved a settlement of the "gaming" proceeding without finding of wrongdoing by Idaho Power.

The orders establishing the scope of the show cause proceedings are presently the subject of review petitions in the Ninth Circuit. Although IE and Idaho Power are unable to predict how or when the Ninth Circuit will act on these review petitions, in light of the settlement described above, IE and Idaho Power believe this matter will not have a material adverse effect on their consolidated financial positions, results of operations or cash flows.

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, but the FERC terminated its investigations as to Idaho Power on May 12, 2004. California government agencies and California investor-owned utilities have appealed the FERC's termination of this investigation as to Idaho Power and more than 30 other market participants. IE and Idaho Power are unable to predict the outcome of these petitions for review proceedings, but believe that the settlement 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 2003, the FERC terminated the proceeding and declined to order refunds, but in 2007 the Ninth Circuit issued an opinion, in *Port of Seattle, Washington v. FERC*, 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 (CDWR) in the scope of proceeding. The Ninth Circuit officially returned the case to the FERC on April 16, 2009. On September 4, 2009, IE and Idaho Power joined with a number of other parties in a joint petition for a writ of certiorari to the U.S. Supreme Court, which was denied on January 11, 2010.

In separate filings, the California Parties, which no longer include the California Electricity Oversight Board, and the City of Tacoma, Washington and the Port of Seattle, Washington asked the FERC to take actions to reorganize and restructure the case so that they may pursue claims that all spot market sales in the Cal ISO and CalPX markets and in the Pacific Northwest from January 1, 2000 through June 20, 2001 should be repriced, and thereby become subject to refund, because market manipulation and tariff violations affected spot market prices. This would expand the scope of the refund period in the Pacific Northwest proceeding from the December 25, 2000 through June 20, 2001 period previously considered by the FERC. On May 22, 2009, the California Parties filed a motion with the FERC to sever the CDWR sales from the remainder of the Pacific Northwest proceedings and to consolidate the CDWR sales portion of the Pacific Northwest case with ongoing proceedings in cases that IE and Idaho Power have settled and with a new complaint filed on May 22, 2009 by the California Attorney General against parties with whom the California Parties have not settled (Brown Complaint). IE and Idaho Power, along with a number of other parties, filed their opposition to the motion of the California Parties. Many other parties also filed responses to the motion of the California Parties. The City of Tacoma, Washington and the Port of Seattle, Washington filed a motion on August 4, 2009 with the FERC in connection with the California refund proceeding, the *Lockyer* remand pending before the FERC (involving claims of failure to file quarterly transaction reports with the FERC, from which IE and Idaho Power previously were dismissed), the Brown Complaint and the Pacific Northwest refund remand proceeding. The City of Tacoma and the Port of Seattle motion asks the FERC, either on a summary basis or after new evidentiary hearings, to require refunds from all sellers in the Pacific Northwest spot markets for the expanded period (January 1, 2000 through June 20, 2001). IE and Idaho Power joined with a number of other sellers in the Pacific Northwest markets during 2000 and 2001 in opposing the motion of the City of Tacoma and the Port of Seattle. IE and Idaho Power intend to vigorously defend their positions in these proceedings, but are unable to predict the outcome of these matters or estimate the impact these matters may have on their consolidated financial positions, results of operations or cash flows.

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 Idaho Power and other unrelated entities as defendants. Plaintiffs allege that Idaho Power'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, and entered judgment in favor of Idaho Power on January 25, 2008. Plaintiffs appealed the district court's decision to the Ninth Circuit which affirmed the district court's dismissal of the action. The time within which plaintiffs could pursue further review has expired.

Sierra Club Lawsuit-Bridger: In February 2007, the Sierra Club and the Wyoming Outdoor Council filed a complaint against PacifiCorp in the U.S. District Court for the District of 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 by the flue gas of a power plant. The complaint alleged thousands of opacity permit violations by PacifiCorp and sought a declaration that PacifiCorp had 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 plaintiffs' costs of litigation, including reasonable attorneys' fees. Idaho Power is not a party to this proceeding but has a one-third ownership interest in the plant. PacifiCorp owns a two-thirds interest in and is the operator of the plant. On February 10, 2010, PacifiCorp and plaintiffs reached an agreement in principle to the settlement of the lawsuit in its entirety. The settlement is subject to the approval of the Environmental Protection Agency and the court. If approved, the settlement will not have a material adverse effect on Idaho Power's consolidated financial positions, results of operations or cash flows.

Sierra Club Lawsuit – Boardman: In September 2008, the 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 plant located in Morrow County, Oregon. The complaint also alleged 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 sought a declaration that PGE had 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 reimbursement of plaintiffs' costs of litigation, including reasonable attorneys' fees. Idaho Power 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. On September 30, 2009, the court denied most of PGE's motion to dismiss. Idaho Power continues 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: Idaho Power 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 Idaho Power.

On March 25, 2009, Idaho Power and the State of Idaho (State) entered into a settlement agreement with respect to the 1984 Swan Falls Agreement and Idaho Power's water rights under the Swan Falls Agreement, which settlement agreement is subject to certain conditions discussed below. The settlement agreement will also resolve litigation between Idaho Power and the State relating to the Swan Falls Agreement that was filed by Idaho Power on May 10, 2007, with the Idaho District Court for the Fifth Judicial Circuit, which has jurisdiction over SRBA matters including the Swan Falls case.

The settlement agreement resolves the pending litigation by clarifying that Idaho Power's water rights in excess of minimum flows at its hydroelectric facilities between Milner Dam and Swan Falls Dam are subordinate to future upstream beneficial uses, including aquifer recharge. The agreement commits the State and Idaho Power to further discussions on important water management issues concerning the Swan Falls Agreement and the management of water in the Snake River Basin. It also recognizes that water management measures that enhance aquifer levels, springs and river flows, such as aquifer recharge projects, benefit both agricultural development and hydropower generation and deserve study to determine their economic potential, their impact on the environment and their impact on hydropower generation. These will be a part of the Comprehensive Aquifer Management Plan (CAMP), approved by the Idaho Water Resource Board for the Eastern Snake Plain Aquifer (ESPA), which includes limits on the amount of aquifer recharge. Idaho Power is a member of the ESPA CAMP advisory committee and implementation committee.

On April 24, 2009, the Governor of Idaho signed into law legislation approving provisions contained in the settlement agreement. On May 6, 2009, as part of the settlement, Idaho Power, the Governor of Idaho and the Idaho Water Resource Board executed a memorandum of agreement relating to future aquifer recharge efforts and further assurances as to limitations on the amount of aquifer recharge. Idaho Power and the State also filed a joint motion to the SRBA court to dismiss the Swan Falls case and enter the stipulated water right decrees set forth in the settlement agreement. Parties representing groundwater users in the Eastern Snake Plain Aquifer objected to some of the language proposed by Idaho Power and the State relating to water rights in the decrees to be entered by the SRBA court as contemplated by the Settlement Agreement. Specifically, the concerns relate to the language describing the subordination of the rights and its interplay with the original Swan Falls settlement document and implementing legislation. On January 4, 2010, the court issued an order approving the overall settlement subject to certain modifications to the draft water right decrees proposed by the company and the state. The company is working with the state and the parties to reach agreement consistent with the court's order regarding the language of the decrees.

U.S. Bureau of Reclamation: Idaho Power filed a complaint on October 15, 2007 and an amended complaint on September 30, 2008 in the U.S. District Court of Federal Claims in Washington, D.C. against the U.S. Bureau of Reclamation. The complaint relates to a contract right for delivery of water to its hydropower projects on the Snake River to recover damages from the U.S. for the lost generation resulting from reduced flows and a prospective declaration of contractual rights so as to prevent the U.S. from continued failure to fulfill its contractual and fiduciary duties to Idaho Power. In 1923, Idaho Power and the U.S. entered into a contract that facilitated the development of the American Falls Reservoir by the U.S. on the Snake River in southeast Idaho. This 1923 contract entitles Idaho Power to 45,500 acre-feet of primary storage capacity in the reservoir and 255,000 acre-feet of secondary storage that was to be available to Idaho Power between October 1 of any year and June 10 of the following year as necessary to maintain specified water flows at Idaho Power's Twin Falls power plant below Milner Dam. Idaho Power believes that the U.S. has failed to deliver this secondary storage, at the specified flows, since 2001. Discovery is scheduled to be completed by March 3, 2010. Trial of the matter has not been scheduled. Idaho Power is unable to predict the outcome of this action.

Oregon Trail Heights Fire: On August 25, 2008, a fire ignited beneath an Idaho Power 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 Idaho Power's distribution poles and that high winds contributed to the fire and its resultant damage.

Idaho Power has received notice of claims from a number of the homeowners and their insurers and while it has continued investigation of these claims, Idaho Power has reached settlements with a number of the individuals or their insurers who have alleged damages resulting from the fire. Idaho Power is insured up to policy limits against liability for claims in excess of its self-insured retention. Idaho Power has accrued 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 Idaho Power is party to legal claims, actions and proceedings in addition to those discussed above. Resolution of any of these matters will take time and the companies cannot predict the outcome of any of these proceedings. The companies believe that their reserves are adequate for these matters and that resolution of these matters, taking into account existing reserves, will not have a material adverse effect on Idaho Power's financial position, results of operations or cash flows.

10. BENEFIT PLANS:

Pension Plans

Idaho Power 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. Idaho Power'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. Idaho Power was not required to contribute to the plan in 2009 or 2008. 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, Idaho Power has a nonqualified, deferred compensation plan for certain senior management employees and directors called the Senior Management Security Plan (SMSP). At December 31, 2009 and 2008, approximately \$40.3 million and \$39.9 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	
	2009	**2008**	**2009**	**2008**
	(thousands of dollars)			
Change in benefit obligation:				
Benefit obligation at January 1	$ 464,416	$ 420,526	$ 48,393	$ 43,153
Service cost	16,514	14,920	1,610	1,278

Interest cost	27,865	26,393	2,854	2,669
Actuarial loss	16,193	19,547	3,156	3,376
Benefits paid	(18,244)	(16,970)	(3,294)	(2,644)
Plan amendments	-	-	-	561
Benefit obligation at December 31	506,744	464,416	52,719	48,393
Change in plan assets:				
Fair value at January 1	295,324	407,970	-	-
Actual return on plan assets	36,394	(95,676)	-	-
Benefits paid	(18,244)	(16,970)	-	-
Fair value at December 31	313,474	295,324	-	-
Funded status at end of year	$ (193,270)	$ (169,092)	$ (52,719)	$ (48,393)
Amounts recognized in the statement of financial position consist of:				
Other current liabilities	$ -	-	$ (3,244)	$ (2,883)
Noncurrent liabilities (1)	(193,270)	(169,092)	(49,475)	(45,510)
Net amount recognized	$ (193,270)	$ (169,092)	$ (52,719)	$ (48,393)
Amounts recognized in accumulated other comprehensive income consist of:				
Net loss	$ 150,196	$ 155,289	$ 14,585	$ 12,088
Prior service cost	2,505	3,155	1,977	2,209
Subtotal	152,701	158,444	16,562	14,297
Less amount recorded as regulatory asset	(152,701)	(158,444)	-	-
Net amount recognized in accumulated other comprehensive income	$ -	$ -	$ 16,562	$ 14,297
Accumulated benefit obligation	$ 425,744	$ 385,002	$ 48,563	$ 44,275

(1) Noncurrent liabilities are contained in Idaho Power'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	
	2009	2008	2009	2008
	(thousands of dollars)			
Service cost	$ 16,514	$ 14,920	$ 1,610	$ 1,278
Interest cost	27,865	26,393	2,854	2,669
Expected return on assets	(23,965)	(34,112)	-	-
Amortization of net loss	8,857	-	232	489
Amortization of prior service cost	650	650	659	192
Net periodic pension cost	$ 29,921	$ 7,851	$ 5,355	$ 4,628

In 2010, Idaho Power expects to recognize as components of net periodic benefit cost $9.5 million from amortizing amounts recorded in accumulated other comprehensive income (or as a regulatory asset for the pension plan) as of December 31, 2009, relating to the pension and SMSP plans. This amount consists of $7.7 million of amortization of net loss, and $0.7 million of amortization of prior service cost for the pension plan and $0.9 million of amortization of net loss and $0.2 million of amortization of prior service cost for the SMSP.

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

	2010	2011	2012	2013	2014	2015-2019
			(thousands of dollars)			
Pension Plan	$ 19,453	$ 20,785	$ 22,654	$ 24,716	$ 26,586	$ 169,665
SMSP	$ 3,332	$ 3,349	$ 3,483	$ 3,703	$ 3,890	$ 21,000

Pension Protection Act: In accordance with the Pension Protection Act of 2006 (PPA), and the relief provisions of the Worker, Retiree, and Employer Recovery Act of 2008 (WRERA), which was signed into law on December 23, 2008, companies are required to meet minimum funding levels in order to avoid benefit restrictions. The WRERA also provides for asset smoothing, which allows the use of asset averaging, including expected returns (subject to certain limitations), for a 24-month period in the determination of the funding requirements. Idaho Power has elected to use asset smoothing.

On March 31, 2009, the U.S. Department of the Treasury (Treasury) provided guidance on the selection of the corporate bond yield curve for determining plan liabilities and allows companies to choose from a range of months in selecting a yield curve, rather than requiring the use of prescribed rates. The Treasury's announcement specifically referenced 2009, but also indicated that technical guidance will be forthcoming to address future years. The revisions in the PPA, WRERA, Treasury guidance, and IRS guidance resulted in Idaho Power revising the funded status as of January 1, 2009, effectively reducing or delaying the required contributions from Idaho Power from what would otherwise be required, and what was previously disclosed. At January 1, 2009, Idaho Power's pension plan was above the minimum required funding levels as revised by the PPA, WRERA, Treasury guidance and IRS guidance, but below the minimum required funding levels at January 1, 2010, and is projected to stay below the minimum required funding levels through 2015. As Idaho Power's pension plan is below the minimum required funding levels at January 1, 2010, future minimum contributions are required. Based on the provisions and methodologies allowed under the PPA, WRERA, Treasury guidance and IRS guidance, Idaho Power was not required to contribute to their pension plan in 2009, and estimated minimum required contributions will be approximately $6 million in 2010, $44 million in 2011 $47 million in 2012, $39 million in 2013, and $40 million in 2014. Idaho Power may elect to make contributions earlier than the required dates.

The IRS and Treasury have issued final regulations effective October 15, 2009 that apply to plan years beginning on or after January 1, 2010. These regulations reflect provisions added by the PPA, as amended by the WRERA. These regulations affect sponsors, administrators, participants, and beneficiaries of single employer defined benefit pension plans. The regulations provide guidance regarding the determination of the value of plan assets and benefit liabilities for purposes of the funding requirements, regarding the use of certain funding balances maintained for those plans, and regarding benefit restrictions for certain underfunded defined benefit pension plans. These final regulations did not materially change existing estimates relating to pension plan contributions.

Additional legislative or regulatory measures, as well as fluctuations in financial market conditions, may impact funding requirements. Idaho Power continues to monitor the legislative and regulatory environments for additional changes, evaluating them for their potential impact on funding requirements and strategies.

Postretirement Benefits

Idaho Power 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 Idaho Power's future obligations under this plan.

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

	2009	2008
Change in accumulated benefit obligation:		
Benefit obligation at January 1	$ 59,648	$ 56,826
Service cost	1,221	1,154
Interest cost	3,565	3,498
Actuarial loss	2,128	1,656
Benefits paid(1)	(3,915)	(3,486)
Benefit obligation at December 31	62,647	59,648

Change in plan assets:				
Fair value of plan assets at January 1		25,283		35,096
Actual return on plan assets		5,609		(7,834)
Employer contributions		3,915		1,507
Benefits paid(1)		(3,915)		(3,486)
Fair value of plan assets at December 31		30,892		25,283
Funded status at end of year (included in noncurrent liabilities)(2)	$	(31,755)	$	(34,365)

(1) Benefits paid are net of $2,731 and $1,927 of plan participant contributions, and $385 and $421 of Medicare Part D subsidy receipts for 2009 and 2008, respectively.

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

Amounts recognized in accumulated other comprehensive income consist of:

Net loss	$	14,112	$	16,289
Prior service cost (credit)		(1,537)		(2,072)
Transition obligation		6,120		8,160
Subtotal		18,695		22,377
Less amount recognized in regulatory assets		(15,235)		(18,904)
Less amount included in deferred tax assets		(3,460)		(3,473)
Net amount recognized in accumulated other comprehensive income	$	-	$	-

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

		2009		2008
Service cost	$	1,221	$	1,154
Interest cost		3,565		3,498
Expected return on plan assets		(2,146)		(2,899)
Amortization of net loss		842		-
Amortization of prior service cost		(535)		(535)
Amortization of unrecognized transition obligation		2,040		2,040
Net periodic postretirement benefit cost	$	4,987	$	3,258

In 2010, Idaho Power expects to recognize as components of net periodic benefit cost $2.1 million from amortizing amounts recorded in accumulated other comprehensive income as of December 31, 2009 relating to the postretirement plan. This amount consists of ($0.5) million of prior service cost, $0.6 million of net loss and $2.0 million of transition obligation.

Medicare Act: The Medicare Prescription Drug, Improvement and Modernization Act of 2003 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):

	2010	2011	2012	2013	2014	2015-2019
Expected benefit payments(1)	$ 4,200	$ 4,400	$ 4,500	$ 4,700	$ 4,800	$ 25,200
Expected Medicare Part D						

subsidy receipts	$	500	$	500	$	600	$	600	$	700	$	4,500

(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 eight percent and ten percent in 2009 and 2008, respectively. The assumed health care cost trend rate for 2009 is assumed to decrease gradually to five percent by 2066. The assumed dental cost trend rate used to measure the expected cost of dental benefits covered by the plan was five percent in both 2009 and 2008. A 1-percentage point change in the assumed health care cost trend rate would have the following effects at December 31, 2009 (in thousands of dollars):

	1-Percentage-Point Increase	1-Percentage-Point Decrease
Effect on total of cost components	$ 288	$ (218)
Effect on accumulated postretirement benefit obligation	$ 2,471	$ (1,949)

Plan Assumptions:

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

	Pension Benefits		Postretirement Benefits	
	2009	2008	2009	2008
Discount rate	5.9%	6.1%	5.9%	6.1%
Rate of compensation increase	4.5%	4.5%	-	-
Medical trend rate	-	-	8.0%	10.0%
Dental trend rate	-	-	5.0%	5.0%
Measurement date	12/31/09	12/31/08	12/31/09	12/31/08

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

	Pension Benefits		Postretirement Benefits	
	2009	2008	2009	2008
Discount rate	6.1%	6.4%	6.1%	6.4%
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	-	-	8.0%	10.0 %
Dental trend rate	-	-	5.0%	5.0%

Plan Assets:

Idaho Power's pension plan and postretirement benefit plan assets at December 31, by asset category, are as follows:

	Pension Plan		Postretirement Benefits	
Asset Category	2009	2008	2009	2008

Cash and cash equivalents	$ 4,512	$ 4,666	$ -	$ -
Short-term bonds	30,774	36,553	-	-
Core bonds	41,165	46,652	-	-
Equity securities	184,562	152,172	-	-
Real estate	20,783	37,418	-	-
Private market investments	20,202	17,863	-	-
Commodities	11,476	-	-	-
Other(1)	-	-	30,892	25,283
Total	$ 313,474	$ 295,324	$ 30,892	$ 25,283

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

Pension Asset Allocation Policy: The target allocation and actual allocations at December 31, 2009 for the portfolio by asset class are as follows:

	Target Allocation	Actual Allocation December 31, 2009
Large-cap core stocks	14%	12.2%
Large-cap growth stocks	7%	9.2%
Large-cap value stocks	7%	9.0%
Small-cap growth stocks	5%	4.5%
Small-cap value stocks	5%	5.3%
Micro-cap stocks	3%	3.2%
International growth stocks	7%	7.2%
International value stocks	7%	8.3%
Commodities	3%	3.7%
Private market investments	7%	6.5%
Short-term bonds	10%	9.8%
Core bonds	13%	13.1%
Cash and cash equivalents	3%	1.4%
Real estate	9%	6.6%
Total	100%	100%

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 Idaho Power'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. Idaho Power sets bond allocations sufficient to cover at least five years of benefit payments and cash allocations sufficient to cover the current year benefit payments. Idaho Power 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.

Idaho Power'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.

Fair Value of Plan Assets: Idaho Power classifies its pension plan and postretirement plan investments using the following hierarchy:

- Level 1, which refers to securities valued using quoted prices from active markets for identical assets;
- Level 2, which refers to securities not traded on an active market but for which observable market inputs are readily available; and
- Level 3, which refers to securities valued based on significant unobservable inputs.

If the inputs used to measure the securities fall within different levels of the hierarchy, the categorization is based on the lowest level input (Level 3 being the lowest) that is significant to the fair value measurement of the security. The following table sets forth by level within the fair value hierarchy a summary of the plans' investments measured at fair value on a recurring basis at December 31.

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Assets at December 31, 2009				
Pension assets:				
Cash and cash equivalents	$ 4,512	$ -	$ -	$ 4,512
Short-term bonds	30,774	-	-	30,774
Core bonds	41,165	-	-	41,165
Equity securities	126,049	58,513	-	184,562
Real estate	-	-	20,783	20,783
Private market investments	-	-	20,202	20,202
Commodities	-	11,476	-	11,476
Total pension assets	$ 202,500	$ 69,989	$ 40,985	$ 313,474
Postretirement assets	$ -	$ 30,892	$ -	$ 30,892

The following table presents a reconciliation of the beginning and ending balances of the fair value measurements using significant unobservable inputs (Level 3):

	Private Equity	Real Estate	Total
Beginning balance - January 1, 2009	$ 17,863	$ 37,418	$ 55,281
Realized losses	(1,040)	(671)	(1,711)
Unrealized gains (losses)	3,103	(14,912)	(11,809)
Purchases, issuances, and settlements, net	276	(1,052)	(776)
Ending balance - December 31, 2009	$ 20,202	$ 20,783	$ 40,985

Employee Savings Plan
Idaho Power has an Employee Savings Plan that complies with Section 401(k) of the Internal Revenue Code and covers substantially all employees. Idaho Power matches specified percentages of employee contributions to the plan. Matching contributions amounted to $5 million in each of 2009 and 2008.

Post-employment Benefits
Idaho Power 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 Idaho Power's disability plans and health care for surviving spouses and dependents. Idaho Power accrues a liability for such benefits. The post employment benefit amounts included in other deferred credits on Idaho Power's balance sheets at December 31, 2009 and 2008 are $5.2 million and $3.7 million, respectively.

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

The following table presents the major classifications of Idaho Power's utility plant in service, annual depreciation provisions as a percent of average depreciable balance and accumulated provision for depreciation for the years 2009 and 2008 (in thousands of dollars):

	2009		2008	
	Balance	Avg Rate	Balance	Avg Rate
Production	$ 1,758,813	2.23%	$ 1,736,670	2.34%
Transmission	768,260	2.07	742,871	2.11
Distribution	1,331,065	2.89	1,254,048	2.50
General and Other	302,040	7.88	296,545	7.53
Total in service	4,160,178	2.81%	4,030,134	2.73%
Accumulated provision for depreciation	(1,558,538)		(1,505,120)	
In service - net	$ 2,601,640		$ 2,525,014	

Idaho Power has interests in three jointly-owned generating facilities included in the table above. Under the joint operating agreements, each participating utility is responsible for financing its share of construction, operating and leasing costs. Idaho Power'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 Idaho Power's participation, were as follows at December 31, 2009 (in thousands of dollars):

Name of Plant	Location	Utility Plant In Service	Construction Work in Progress	Accumulated Provision for Depreciation	Ownership %	MW(1)
Jim Bridger Units 1-4	Rock Springs, WY	$ 505,343	$ 21,922	$ 274,852	33	771
Boardman	Boardman, OR	71,755	630	51,677	10	64
Valmy Units 1 and 2	Winnemucca, NV	334,152	6,040	207,808	50	284

(1) Idaho Power share of nameplate capacity

Idaho Power'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. Idaho Power's coal purchases from the joint venture were $66 million and $63 million in 2009 and 2008, respectively.

Idaho Power has contracts to purchase the energy from four PURPA qualified facilities that are 50 percent owned by Ida-West. Idaho Power's power purchases from these facilities were $8.7 million in 2009 and $8 million in 2008.

12. ASSET RETIREMENT OBLIGATIONS (ARO):

The guidance relating to accounting for AROs 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 the guidance, 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, Idaho Power 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.

Idaho Power'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 2009, changes in estimates at the coal-fired generation facilities resulted in a net increase of $3.7 million in the recorded ARO.

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

	2009	2008
Balance at beginning of year	$ 12,415	$ 14,515
Accretion expense	697	701
Revisions in estimated cash flows	3,684	(2,627)
Liability incurred	139	-
Liability settled	(695)	(174)
Balance at end of year	$ 16,240	$ 12,415

13. INVESTMENTS:

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

	2009	2008
Investments:		
Equity method investment	$ 83,969	$ 86,433
Available-for-sale equity securities	18,842	14,451
Executive deferred compensation plan	5,217	4,679
Other investments	267	948
Total investments	$ 108,295	$ 106,511

Equity Method Investments
Idaho Power, 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 Idaho Power.

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

	2009	2008
Bridger Coal Company	$ 8,256	$ 6,772

Investments in Debt and Equity Securities
Investments in debt and equity securities 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.

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

	2009			2008		
	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
Available-for-sale securities	$ 2,989	$ -	$ 18,842	$ -	$ -	$ 14,451

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

	2009	2008
Proceeds from sales	$ 9,006	$ -
Gross realized gains from sales	11	-
Gross realized losses from sales	35	-

These investments are evaluated to determine whether they have experienced a decline in market value that is other-than-temporary. Idaho Power analyzes securities in loss positions as of the end of each reporting period. At December 31, 2009, Idaho Power did not have any securities that were in a loss position. 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 were broadly diversified index funds used to fund Idaho Power's SMSP. Due to the severity of the losses and the volatility of the market the available-for-sale securities were deemed other-than-temporarily impaired and written down $6.8 million to fair market value at December 31, 2008. The held-to-maturity debt securities were bonds with an aggregate fair value of approximately $4 million and an aggregate unrealized loss of $25 thousand at December 31, 2008. The bonds market values fluctuated based on the interest rate environment.

14. DERIVATIVE FINANCIAL INSTRUMENTS

Commodity Price Risk
Idaho Power is exposed to certain risks relating to its ongoing business operations. The primary risk managed by using derivative instruments is commodity price risk related to Idaho Power's ongoing utility operations providing electricity to meet the demand of its retail customers. Physical and financial forward contracts for both electricity and fuel used to produce electricity are entered into to manage the price risk associated with meeting forecasted loads. The objective of Idaho Power's energy purchase and sale activity is to meet the demand of retail electric customers, maintain appropriate physical reserves to ensure reliability and make economic use of temporary surpluses that may develop.

All derivative instruments are recognized as either assets or liabilities at fair value on the balance sheet. Idaho Power's physical forward contracts qualify for the normal purchases and normal sales exception to derivative accounting requirements with the exception of forward contracts for the purchase of natural gas for use at Idaho Power's natural gas generation facilities. Because of Idaho Power's power cost mechanisms, Idaho Power records the changes in fair value of derivative instruments related to power supply as regulatory assets or liabilities.

As of December 31, 2009, Idaho Power had the following outstanding derivative commodity forward contracts that were entered into for the purpose of economically hedging forecasted purchases and sales:

Commodity	Number of Units	
Electricity purchases	705,625	MWh
Electricity sales	567,525	MWh
Natural gas	1,356,250	MMBtu
Diesel	901,932	gallons

The following table presents the fair values of derivatives not designated as hedging instruments recorded in the balance sheet at December 31, 2009 (in thousands of dollars):

	Asset Derivatives		Liability Derivatives	
Commodity derivatives	**Balance Sheet Location**	**Fair Value**	**Balance Sheet Location**	**Fair Value**
Current:				
Financial swaps	Other current assets	$ 2,931	Other current assets	$ 2,087
Financial swaps	Other current liabilities	9	Other current liabilities	610
Forward contracts	Other current assets	354	Other current assets	-
Long-term:				
Financial swaps	Other assets	442	Other assets	229
Total		$ 3,736		$ 2,926

The following table presents the effect on income of derivatives not designated as hedging instruments for the year ended December 31, 2009 (in thousands of dollars):

Commodity derivatives	Location of Gain/(Loss) Recognized in Income on Derivative	Amount of Gain/(Loss) Recognized in Income on Derivative(1)
Year ended December 31, 2009:		
Financial swaps	Off-system sales	$ 3,245
Financial swaps	Purchased power	(3,966)
Financial swaps	Fuel expense	(5,794)
Forward contracts	Fuel expense	(986)

(1) Excludes changes in fair value of derivatives, which are recorded on the balance sheet as regulatory assets or liabilities.

Idaho Power records changes in fair value of its derivative contracts as either regulatory assets or liabilities. Settlement gains and losses on electricity swap contracts are recorded on the income statement in off-system sales or purchased power depending on the forecasted position being economically hedged by the derivative contract. Settlement gains and losses on both financial and physical contracts for natural gas are reflected in fuel expense. Settlement gains and losses on diesel derivatives, which were immaterial for all three years, are recorded in fuel inventory on the balance sheet.

Credit Risk

At December 31, 2009, Idaho Power does not have material credit exposure from financial instruments, including derivatives. Idaho Power monitors credit risk exposure through reviews of counterparty credit quality, corporate-wide counterparty credit exposure, and corporate-wide counterparty concentration levels. Idaho Power manages these risks by establishing appropriate credit and concentration limits on transactions with counterparties and requiring contractual guarantees, cash deposits or letters of credit from counterparties or their affiliates, as deemed necessary. The majority of Idaho Power's contracts are under the Western Systems Power

Pool agreement that provides for adequate assurances if a counterparty has debt that is downgraded to below investment grade by at least one rating agency. Idaho Power also requires North American Energy Standards Board contracts as necessary for physical gas transactions, and International Swaps and Derivatives Association, Inc. contracts as needed for financial transactions.

Credit-Contingent Features

Certain of Idaho Power's derivative instruments contain provisions that require Idaho Power's unsecured debt to maintain an investment grade credit rating from each of the major credit rating agencies. If Idaho Power's unsecured debt were to fall below investment grade, it would be in violation of these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that are in a liability position on December 31, 2009, is $2.9 million. Idaho Power has posted $1.3 million collateral related to this amount. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2009, Idaho Power could have been required to post $0.5 million of cash collateral to its counterparties.

15. FAIR VALUE MEASUREMENTS:

Idaho Power has categorized its 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 Idaho Power 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.

Idaho Power 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.

Idaho Power'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 and diesel 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 information about Idaho Power's assets and liabilities measured at fair value on a recurring basis (in thousands of dollars). Idaho Power'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. Please see Note 10 for fair value information regarding Idaho Power's benefit plans.

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
2009				
Assets:				
Derivatives	$ 1,056	$ 354	$ -	$ 1,410
Money market funds	19,364	-	-	19,364
Trading securities	5,217	-	-	5,217
Available-for-sale equity securities	18,842	-	-	18,842
Liabilities:				
Derivatives	(601)	-	-	(601)
2008				
Assets:				
Derivatives	$ 652	$ -	$ -	$ 652
Money market funds	1,224	-	-	1,224
Trading securities	4,679	-	-	4,679
Available-for-sale equity securities	14,451	-	-	14,451
Liabilities:				
Derivatives	-	(2,653)	-	(2,653)

The following tables present the carrying value and estimated fair value of 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, 2009		December 31, 2008	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	(thousands of dollars)			
Assets:				
Notes receivable	$ -	$ -	$ 259	$ 282
Liabilities:				
Long-term debt	1,413,854	1,398,681	1,268,818	1,191,476

16. OTHER INCOME AND EXPENSE:

The following table presents the components of Other income and Other expense (in thousands of dollars):

	2009	2008
Other income:		
Allowance for funds used during construction-equity	$ 7,555	$ 3,141
Investment income, net	5,071	(5,273)
Carrying charges	4,471	6,709
Other	3,967	7,284
Total	$ 21,064	$ 11,861
Other expense:		
SMSP expense	$ 5,355	$ 4,628

Life Insurance, net of proceeds	(4,197)	(381)
Other	2,909	3,783
Total	$ 4,067	$ 8,030

17. RELATED PARTY TRANSACTIONS:

IDACORP
Idaho Power performs corporate functions such as financial, legal and management services for IDACORP and its subsidiaries. Idaho Power charges IDACORP for the costs of these services based on service agreements and other specifically identified costs. For these services Idaho Power billed IDACORP $0.9 million and $1 million in 2009 and 2008, respectively.

Ida-West
Idaho Power purchases all of the power generated by four of Ida-West's hydroelectric projects located in Idaho. Idaho Power paid $8.7 million in 2009 and $8 million in 2008.

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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	04/12/2010	End of 2009/Q4

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

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

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	4,160,632,424	4,160,632,424
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	4,160,632,424	4,160,632,424
9	Leased to Others		
10	Held for Future Use	7,150,794	7,150,794
11	Construction Work in Progress	289,188,358	289,188,358
12	Acquisition Adjustments	-454,449	-454,449
13	Total Utility Plant (8 thru 12)	4,456,517,127	4,456,517,127
14	Accum Prov for Depr, Amort, & Depl	1,713,943,062	1,713,943,062
15	Net Utility Plant (13 less 14)	2,742,574,065	2,742,574,065
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	1,693,322,507	1,693,322,507
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	21,016,304	21,016,304
22	Total In Service (18 thru 21)	1,714,338,811	1,714,338,811
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	-395,749	-395,749
33	Total Accum Prov (equals 14) (22,26,30,31,32)	1,713,943,062	1,713,943,062

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	04/12/2010	End of 2009/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	55,947	-101,951
3	(302) Franchises and Consents	21,714,184	-93,415
4	(303) Miscellaneous Intangible Plant	33,064,583	6,481,720
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	54,834,714	6,286,354
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,370,320	
9	(311) Structures and Improvements	134,509,144	4,428,791
10	(312) Boiler Plant Equipment	536,613,056	15,667,072
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	132,560,576	5,376,696
13	(315) Accessory Electric Equipment	62,162,175	781,896
14	(316) Misc. Power Plant Equipment	16,343,159	-467,254
15	(317) Asset Retirement Costs for Steam Production	4,362,002	-776,491
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	887,920,432	25,010,710
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	28,655,168	2,167,400
28	(331) Structures and Improvements	151,277,057	2,376,592
29	(332) Reservoirs, Dams, and Waterways	249,507,983	797,436
30	(333) Water Wheels, Turbines, and Generators	188,274,619	4,883,815
31	(334) Accessory Electric Equipment	41,330,716	1,985,661
32	(335) Misc. Power PLant Equipment	17,467,963	646,843
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)	684,006,191	12,857,747
36	D. Other Production Plant		
37	(340) Land and Land Rights	402,746	
38	(341) Structures and Improvements	10,422,006	-3,252,411
39	(342) Fuel Holders, Products, and Accessories	5,330,580	-884,714
40	(343) Prime Movers	91,489,425	1,999,610
41	(344) Generators	36,237,868	2,855,158
42	(345) Accessory Electric Equipment	17,237,981	7,661,249
43	(346) Misc. Power Plant Equipment	3,623,146	-568,971
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	164,743,752	7,809,921
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,736,670,375	45,678,378

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/Q4

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

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

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

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

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			-46,004		2
			21,620,769		3
4,786,263			34,760,040		4
4,786,263			56,334,805		5
					6
					7
			1,370,320		8
305,737			138,632,198		9
16,284,072			535,996,056		10
					11
3,178,768			134,758,504		12
933,816			62,010,255		13
691,107			15,184,798		14
			3,585,511		15
21,393,500			891,537,642		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
-463			30,823,031		27
91,478			153,562,171		28
68,477			250,236,942		29
426,420			192,732,014		30
563,480			42,752,897		31
154,973			17,959,833		32
			7,492,685		33
					34
1,304,365			695,559,573		35
					36
			402,746		37
			7,169,595		38
			4,445,866		39
837,464			92,651,571		40
			39,093,026		41
			24,899,230		42
			3,054,175		43
					44
837,464			171,716,209		45
23,535,329			1,758,813,424		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	04/12/2010	End of 2009/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	34,665,687	-3,636,839
49	(352) Structures and Improvements	41,274,219	1,964,780
50	(353) Station Equipment	286,101,340	19,136,925
51	(354) Towers and Fixtures	136,921,634	2,383,729
52	(355) Poles and Fixtures	93,136,953	2,438,869
53	(356) Overhead Conductors and Devices	150,452,740	5,091,772
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)	742,870,924	27,379,236
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	4,715,078	5,906
61	(361) Structures and Improvements	24,515,065	2,535,755
62	(362) Station Equipment	167,223,999	14,885,421
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	210,585,863	8,065,022
65	(365) Overhead Conductors and Devices	116,789,867	5,906,821
66	(366) Underground Conduit	47,417,198	975,808
67	(367) Underground Conductors and Devices	179,509,673	8,562,574
68	(368) Line Transformers	381,826,912	26,216,387
69	(369) Services	55,557,765	1,231,619
70	(370) Meters	58,984,822	20,190,727
71	(371) Installations on Customer Premises	2,536,798	175,494
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	4,152,933	137,944
74	(374) Asset Retirement Costs for Distribution Plant	232,370	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,254,048,343	88,889,478
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	10,828,375	-67,107
87	(390) Structures and Improvements	71,404,395	5,572,161
88	(391) Office Furniture and Equipment	45,904,852	3,160,495
89	(392) Transportation Equipment	58,431,918	2,573,534
90	(393) Stores Equipment	1,182,487	256,639
91	(394) Tools, Shop and Garage Equipment	4,808,712	656,258
92	(395) Laboratory Equipment	10,712,475	1,204,212
93	(396) Power Operated Equipment	8,673,751	589,519
94	(397) Communication Equipment	26,110,806	1,997,252
95	(398) Miscellaneous Equipment	4,106,221	211,716
96	SUBTOTAL (Enter Total of lines 86 thru 95)	242,163,992	16,154,679
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)	242,163,992	16,154,679
100	TOTAL (Accounts 101 and 106)	4,030,588,348	184,388,125
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)	4,030,588,348	184,388,125

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	04/12/2010	End of 2009/Q4

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
			31,028,848		48
123,502			43,115,497		49
1,084,667			304,153,598		50
			139,305,363		51
350,520			95,225,302		52
431,505			155,113,007		53
					54
					55
			318,351		56
					57
1,990,194			768,259,966		58
					59
14			4,720,970		60
101,502			26,949,318		61
744,946			181,364,474		62
					63
1,592,334			217,058,551		64
1,567,490			121,129,198		65
93,597			48,299,409		66
1,098,401			186,973,846		67
6,158,840			401,884,459		68
282,627			56,506,757		69
133,705			79,041,844		70
56,714			2,655,578		71
					72
43,059			4,247,818		73
			232,370		74
11,873,229			1,331,064,592		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			10,761,268		86
320,175			76,656,381		87
8,239,535			40,825,812		88
2,080,609			58,924,843		89
108,332			1,330,794		90
214,765			5,250,205		91
365,201			11,551,486		92
22,682			9,240,588		93
714,934			27,393,124		94
92,801			4,225,136		95
12,159,034			246,159,637		96
					97
					98
12,159,034			246,159,637		99
54,344,049			4,160,632,424		100
					101
					102
					103
54,344,049			4,160,632,424		104

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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			1,099,141
7	Beacon Light Substation	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	Line #854 500 Kv	3/31/09		305,494
11	Boise Operations Center	12/31/82		72,785
12	Transmission Stations	12/31/81		199,069
13	Distribution Stations			72,016
14	Homedale Substation	2/29/08		215,719
15	Beacon Light Substation	12/30/02		601,522
16				
17				
18				
19	Column B if no date listed it is various			
20				
21	Other Property:			
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44				
45				
46				
47	Total			7,150,794

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	04/12/2010	End of 2009/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	IRP - COMBINED CYCLE CT (2012)	52,823,361
2	ROLLUP RELIC COST BROWNLEE	43,330,600
3	HMWY - BUILD HEMINGWAY 500/230	36,254,121
4	ROLLUP RELIC COST HELLS CANYON	29,672,655
5	ROLLUP RELIC COST OXBOW	13,621,964
6	GATEWAY WEST 500KV LINE	11,242,352
7	HELLS CANYON RELICENSING OUTSI	10,533,032
8	BOARDMAN - HEMINGWAY 500 KV LI	8,201,659
9	T7250801 HEMINGWAY - BOWMONT 2	7,569,928
10	CIAC LIABILITY RECLASS	6,194,958
11	BRIDGER 2007C189 U1 SO2 EMIS C	4,254,222
12	WQ - ONGOING HELLS CANYON RELI	4,039,254
13	BRIDGER 2008C123 U1 TURBIN UPG	3,479,448
14	BRIDGER 2007C207 U3 SO2 EMIS C	2,283,130
15	RIVER ENG.-HELLS CANYON CONTIN	2,145,907
16	BRIDGER 2008C124 U1 REHEATER R	2,061,121
17	HCC RELICENSING FISH2004 FEASI	2,005,906
18	PAYROLL & IBNR ACCRUAL	1,979,309
19	IBM MAINFRAME TOOLS LICENSES	1,925,980
20	BRIDGER UNDISTRIBUTED WORK ORD	1,925,675
21	REL-HELLS CANYON COMPLEX FY200	1,895,561
22	HCC RELICENSING, FISH2004 INST	1,735,773
23	HCC RELICENSING, FISH2004 REDB	1,590,625
24	NAMPA REPLACE METALCLAD SWITCH	1,458,489
25	HCC RELICENSING, FISH2004 ANAD	1,406,303
26	VALMY 98230938 RELINE EVAP PON	1,270,215
27	ROLLUP RELIC COST SWAN FALLS	1,167,719
28	BRIDGER 2008C102 U1 GENERATOR	1,135,543
29	SWAN FALLS RELICENSING	1,118,001
30	DESIGN CONSTRUCT WO FOR LINE #	1,111,783
31	COST CENTER 317 DELIVERY CAPIT	1,100,797
32	VALMY 98219836 REPL PRODUCTION	1,081,771
33	342 COST CENTER DELIVERY CAPIT	1,032,297
34	REL-HCC OREGON REAUTHORIZATION	1,012,906
35	LEGAL DEPT. LABOR FOR RELICENS	1,000,569
36	OTHER MINOR PROJECTS UNDER $1,000,000	24,525,424
37		
38		
39		
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41		
42		
43	TOTAL	289,188,358

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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	1,486,751,090	1,486,751,090		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	103,587,447	103,587,447		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	2,765,230	2,765,230		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9	Fuel Stock	108,268	108,268		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	106,460,945	106,460,945		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	49,558,225	49,558,225		
13	Cost of Removal	10,898,807	10,898,807		
14	Salvage (Credit)	4,488,836	4,488,836		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	55,968,196	55,968,196		
16	Other Debit or Cr. Items (Describe, details in footnote):	156,078,668	156,078,668		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,693,322,507	1,693,322,507		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	529,377,124	529,377,124		
21	Nuclear Production				
22	Hydraulic Production-Conventional	324,079,967	324,079,967		
23	Hydraulic Production-Pumped Storage				
24	Other Production	23,160,183	23,160,183		
25	Transmission	252,188,686	252,188,686		
26	Distribution	469,434,706	469,434,706		
27	Regional Transmission and Market Operation				
28	General	95,081,841	95,081,841		
29	TOTAL (Enter Total of lines 20 thru 28)	1,693,322,507	1,693,322,507		

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	04/12/2010	2009/Q4

FOOTNOTE DATA

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

Relocation reimbursements, Up and down costs and damage and insurance claims $ (722,669)

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

Accumulated Provision for Depreciation on Asset Retirement Obligation	$ 758,808
Embedded removal in Accumulated Provision for Depreciation	(156,837,476)

	$(156,078,668)

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	04/12/2010	End of 2009/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

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

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	Idaho Energy Resources Company			
2	Common Stock	02/01/74		500
3	Capital contributions			2,462,594
4	Equity in earnings			57,595,093
5				
6	Subtotal Idaho Energy Resources Company			60,058,187
7				
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41				
42	Total Cost of Account 123.1 $ 2,463,094		TOTAL	60,058,187

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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
4,957,254		62,552,347		4
				5
4,957,254		65,015,441		6
				7
				8
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4,957,254		65,015,441		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	04/12/2010	End of 2009/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)	16,851,868	25,633,645	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)	13,785,883	14,273,494	
8	Transmission Plant (Estimated)	9,182,847	13,295,452	
9	Distribution Plant (Estimated)	20,839,000	15,059,387	
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	597,997	713,727	
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	44,405,727	43,342,060	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)	5,715,442	4,711,966	Electric
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	66,973,037	73,687,671	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets	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	Asset Retirement Obligations- IPUC	10,906,542	4,740,497	230	897,916	14,749,123
2	Order# 29414-OPUC Order# 04-585					
3						
4	SFAS 133 Mark to Market	3,073,630	14,189,919	244	16,983,090	280,459
5						
6	Regulatory Unfunded Accumulated Deferred Income Tax	341,052,611	49,634,578	various	6,625,508	384,061,681
7						
8	PCA Deferral- IPUC order	93,657,207	72,710,549	254/401	134,090,716	32,277,040
9	#27660 (amort period 6/05 thru 5/07)					
10						
11	PCA Prior Year Deferral - IPUC Order	47,163,921	109,706,048	1823/401	117,735,417	39,134,552
12	#27660 (amort period 06/09 thru 05/10)					
13						
14	Fixed Cost Adjusment (FCA) Order #30267	2,721,219	6,581,458	1823	2,721,219	6,581,458
15	(amort period 06/09 thru 05/10)					
16						
17	Prior Year FCA Order #30267		2,739,025	4074/4210	1,484,778	1,254,247
18						
19	Idaho - Demand Side Management - IPUC order	4,863,935		401	3,242,604	1,621,331
20	#27660 (amort period 7/98 thru 6/10)					
21						
22	Excess Power Amortization - OPUC Order#06-070	1,663,272	49,012	401	1,712,284	
23						
24	Excess Power Deferral 06/07 - IPUC Order #07-555	1,214,698	2,380,111	various	2,052,180	1,542,629
25	(amort period 10/09 thru 02/12)					
26						
27	IPUC Grid West loans - IPUC order #30157	559,306		401	186,435	372,871
28	(amort period 1/07 - 12/11)					
29						
30	FERC Grid West Expense - ER08-629-000	363,117		401	83,796	279,321
31	(amort period 05/08 thru 04/13)					
32						
33	SFAS 106/158 Past Retirement Benefits	18,903,935	35,350	228	3,615,120	15,324,165
34	IPUC order #30256					
35						
36	SFAS 87/158 Pension Accumulated	(7,170,251)	5,822,257	various	577,710	-1,925,704
37	IPUC order #30256					
38						
39	Pension Deferred FERC Portion		715,538			715,538
40						
41	Pension Deferred Oregon Order UE-213		572,286			572,286
42						
43	FAS 87 Deferred Pension-IPUC order #30333	10,582,734	29,920,698	various	2,540,153	37,963,279
44	TOTAL	697,644,724	361,096,635		342,909,506	715,831,853

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OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1						
2	FIN 48 Adjustment-Interest Payable-Order #30256	158,444,161	3,764,073	228	9,507,024	152,701,210
3						
4	PS & I Coal Plant - Order #29904	150,092		401	85,767	64,325
5	(amort period 10/2007 thru 9/10)					
6						
7	ID DSM Rider Reclass- 29026	3,942,318	32,111,886	254	26,335,686	9,718,518
8						
9	PCAM Oregon 2008 Order #08-238	5,399,657	5,836,616	various	5,750,854	5,485,419
10						
11	Excess Power Deferral 2007		7,864,376	1823/254	1,671,264	6,193,112
12	IPUC order #09-189					
13						
14	Oregon DSM Rider Reclass- Advice #05-03		1,721,884	143/254	855,112	866,772
15						
16	2009 Reorg order #30914		1,145,203			1,145,203
17	(amort period 01/10 thru 12/14)					
18						
19	OATT Revenue Deferred Reserve Order #30940		7,612,562	186	2,925,724	4,686,838
20	(amort period 01/11 thru 12/13)					
21						
22	Minor items (17)	152,620	1,242,709	various	1,229,149	166,180
23						
24						
25						
26						
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43						
44	TOTAL	697,644,724	361,096,635		342,909,506	715,831,853

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

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Rents - Rights of way	137,573	310,762	165/401	177,967	270,368
2						
3	2008 Poll Control Bond Refin	161,081	5,233,405	various	1,046,585	4,347,901
4						
5	Advance prepaid coal royalties	1,580,516	98	various	73,409	1,507,205
6						
7	Security plan	24,753,750	3,089,672	various	6,977,161	20,866,261
8						
9	American Falls bond refinance	235,262		401	14,553	220,709
10	(amort period 4/00 thru 7/26)					
11						
12	Prepaid Credit Facility	446,435		431	193,067	253,368
13						
14	Company owned Life Insurance	4,728,515	2,946,674	various	1,887,786	5,787,403
15						
16	American Falls water rights	16,758,974		401	1,042,009	15,716,965
17	(amort period 1/06 thru 12/25					
18						
19	Milner bond guarantee	9,572,727		253	1,063,636	8,509,091
20						
21	Southwest intertie project -	2,951,825	3,121,544	various	6,073,369	
22	right of way costs					
23						
24	American Falls - bond refinance	775,986		401	47,999	727,987
25	(35 year amortization)					
26						
27	Shelf Registration - 2008		2,100,982	various	1,126,927	974,055
28						
29	Transmission Deposit-PacifiCorp	661,875	329,245	131/186	329,245	661,875
30						
31	Prepaid Peoplesoft/Passport	134,206	150,619	401	175,229	109,596
32						
33	Boardman Power Plant	149,444	317,228	various	410,996	55,676
34						
35	Long Term Workers Compensation		1,328,786			1,328,786
36						
37	OATT Revenue Deferred Reserve		2,925,724	1823/400	5,851,448	-2,925,724
38	order #30940					
39						
40	Minor Items & Job Orders (9)	11,635	7,051,710	various	6,981,993	81,352
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	63,059,804				58,492,874

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	04/12/2010	End of 2009/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2			
3	Emission Allowances	-3,114,188	-847,076
4	Advances for Construction	9,305,479	8,334,734
5	Other Electric (See footnote)	21,074,809	21,611,994
6			
7	Other (See footnote)	122,738,456	122,807,414
8	TOTAL Electric (Enter Total of lines 2 thru 7)	150,004,556	151,907,066
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	17,642,299	18,203,912
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	167,646,855	170,110,978

Notes

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

(Note 1):	Beginning Balance	Ending Balance
Post Retiree Benefits-VEBA	4,929,292	5,583,994
AFUDC Hells Canyon Relicensing	0	3,868,089
Rate Case Disallowance	2,996,870	2,881,031
Stock Based Compensation	2,316,811	2,235,008
Other Employee's Long Term Deferred Compensation	1,829,072	2,039,678
Post Retirement Benefits	1,044,456	1,765,736
Deferred Idaho ITC	0	1,656,363
Non-VEBA Pension and Benefits	662,313	573,602
Oregon-Pension Expense	0	471,584
FERC Credit OFA	0	424,728
IRS Interest Expense	2,090,777	113,033
Deferred GBC	0	12,000
Provision For Rate Refunds	5,217,171	0
Linden Feeder Deposits	0	0
Bonus Deferral	(6,306)	(2,577)
Delivery Accruals	(5,647)	(10,275)
Total Other Electric	21,074,809	21,611,994

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

(Note 2):		
Pension	61,943,745	59,698,538
Regulatory Liability for Income Taxes	44,340,913	47,183,294
Postretirement Plan	10,863,822	9,450,830
Minimum Pension Liability	5,589,976	6,474,752
Total Other	122,738,456	122,807,414

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

Senior Management Security Plan	12,912,430	13,718,388
SMSP-Market Change of Rabbi Investments	2,669,975	2,669,975
Micron-CIAC	1,764,126	1,526,244
Meridian Gold Contributions	152,679	130,567
Bridger Sierra Reserve-Legal Fee's	97,738	97,738
Unrealized Loss on Investments	-	61,000
Loss on Pioneer Land Write-down	45,351	-
Total Non Electric	17,642,299	18,203,912

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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			
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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) 04/12/2010	Year/Period of Report End of 2009/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
39,150,812	97,877,030					2
						3
39,150,812	97,877,030					4
						5
						6
						7
						8
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						42

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	04/12/2010	End of 2009/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 - None	
2		
3	Account 209 - Reduction in par or stated value of Capital Stock - None	
4		
5	Account 210 - Gain on reacquired Capital Stock - None	
6		
7		
8	Account 211 - Miscellaneous paid-in Capital - None	
9		
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39		
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	04/12/2010	End of 2009/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		
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21		
22	TOTAL	2,096,925

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	04/12/2010	End of 2009/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	4.50% Series due 2020 OPUC #4244 IPUC IPC-E-07-19 WPSC #20005-31-ES-07	130,000,000	234,601 D
4			
5	5.50% Series due 2033	70,000,000	-728,701 P
6			36,400 D
7			
8	6.15% Series Due 2019 OPUC #4244 IPUC IPC-E-07-19 WPSC 20005-31-ES-07	100,000,000	184,949 D
9			-1,034,909 P
10			
11	7.20% Series due 2009	80,000,000	-572,246 P
12			
13	5.30% Series Due 2035	60,000,000	408,411 D
14			-3,844,739 P
15			
16	6.60% Series due 2011	120,000,000	-860,502 P
17			
18	4.25%Series due 2013	70,000,000	-641,201 P
19			374,500 D
20			
21	4.75% Series due 2012	100,000,000	-944,356 P
22			1,047,617 D
23			
24	6.00% Series due 2032	100,000,000	-1,069,356 P
25			543,244 D
26			
27	5.875% Series due 2034	55,000,000	-585,759 P
28			383,322 D
29			
30	5.50% Series due 2034	50,000,000	746,961 D
31			-524,419 P
32			
33	TOTAL	1,663,145,000	-12,808,874

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	04/12/2010	End of 2009/Q4

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
11/20/09	3/1/20	11/20/09	3/1/20	130,000,000	666,250	3
						4
05/01/03	04/01/33	05/01/03	03/31/33	70,000,000	3,850,000	5
						6
						7
4/1/09	4/1/19	4/1/09	4/1/19	100,000,000	4,629,583	8
						9
						10
11/23/99	12/01/09	01/01/00	01/01/10		5,280,000	11
						12
08/26/05	08/26/35	08/26/05	08/26/35	60,000,000	3,180,000	13
						14
						15
03/02/01	03/02/11	03/02/01	03/02/11	120,000,000	7,920,000	16
						17
05/01/03	10/01/13	05/01/03	09/29/13	70,000,000	2,975,000	18
						19
						20
11/15/02	11/15/12	11/15/02	11/15/12	100,000,000	4,750,000	21
						22
						23
11/15/02	11/15/32	11/15/02	11/15/32	100,000,000	6,000,000	24
						25
						26
08/16/04	08/16/34	08/16/04	08/16/34	55,000,000	3,231,250	27
						28
						29
03/26/04	03/15/34	03/26/04	03/15/34	50,000,000	2,750,000	30
						31
						32
				1,413,854,091	73,269,850	33

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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	6.30% Series due 2037	140,000,000	-1,495,799 P
2			273,721 D
3			
4	6.25% Series due 2037	100,000,000	-1,141,489 P
5			266,188 D
6			
7	Port of Morrow Variable due 2027	4,360,000	-188,545 P
8			
9	Humboldt Variable due 2024	49,800,000	-1,697,856 P
10			
11	Sweetwater Variable due 2026	116,300,000	-820,043 P
12			471,252 D
13			
14	6.025 % Series Due 2018	120,000,000	-1,630,120 P
15			
16	2008 Credit Facility	166,100,000	
17	Subtotal Account 221	1,631,560,000	-12,808,874
18			
19	Account 222 - Reaquired Bonds		
20			
21	Account 223: Advances for Associated Companies		
22			
23	Account 224:		
24	Bond Guarantee - American Falls	19,885,000	
25	Note Guarantee - Milner Dam	11,700,000	
26	Subtotal Account 224	31,585,000	
27			
28			
29			
30			
31			
32			
33	TOTAL	1,663,145,000	-12,808,874

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/Q4

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
6/22/07	6/15/2037	6/22/07	6/15/2037	140,000,000	8,820,000	1
						2
						3
10/18/07	10/15/2037	10/18/07	10/15/2037	100,000,000	6,250,000	4
						5
						6
05/17/00	02/01/27	05/17/00	02/01/27	4,360,000	122,024	7
						8
10/22/03	12/01/24	11/01/03	12/01/24	49,800,000	933,266	9
						10
10/3/06	7/15/26	10/3/06	7/15/2026	116,300,000	2,221,815	11
						12
						13
7/10/08	7/15/18	7/10/08	7/15/08	120,000,000	7,230,000	14
						15
4/1/08	3/31/09	4/1/08	3/31/09		2,460,662	16
				1,385,460,000	73,269,850	17
						18
						19
						20
						21
						22
						23
04/26/00	2/1/25			19,885,000		24
02/10/92				8,509,091		25
				28,394,091		26
						27
						28
						29
						30
						31
						32
				1,413,854,091	73,269,850	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	04/12/2010	End of 2009/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)	122,558,984
2		
3		
4	Taxable Income Not Reported on Books	
5		5,561,769
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		89,802,330
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		25,070,070
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		95,047,305
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	86,682,170
28	Show Computation of Tax:	
29	Tenative Federal Tax @ 35%	30,338,760
30		
31		
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Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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FOOTNOTE DATA

Schedule Page: 261 Line No.: 5 Column: b

004003-CONSTRUCTION ADV-252	$	(2,773,559)
004005-AVOIDED COST INT CAP		4,368,718
004006-RETIREMENTS-RECORD TAX GAIN/LOSS		(2,000,000)
004010-EMISSION ALLOWANCE-254.409-411		8,402,722
004013-CIAC AS TAXABLE INC IN ACCT 107		(13,149,262)
004018-LINDEN FEEDER DEPOSITS-253.206		(420,523)
004021-ENGINEERING FEES-IN ACCT 107-FED ONLY		(511,236)
004022-FERC CREDIT OFA-254.307		1,086,401
004501-ROYALTY INCOME BTL		100,000
004506-CIAC-MERIDIAN GOLD		(56,560)
004507-CIAC-MICRON-DRAM		(608,470)
Total	$	(5,561,769)

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

TOTAL FEDERAL AND STATE TAXES DEDUCTED ON BOOKS	$	32,573,455
005001-BAD DEBT EXPENSE		266,407
005010-SFAS 112-POST-EMPLY BEN 182/253		1,844,942
005014-OVERACCRUED VACATION-ACCT 242		194,394
005017-INJURIES & DAMAGES		(2,592,781)
005019-DIRECTORS FEES DEF		353,238
005022-CAPITALIZED OVERHEADS		(10,000,000)
005024-MEALS (50% NON-DEDUCTIBLE) CHRGD TO R.E.		600,000
005025-MILNER FALLING WATER - REV ACCRL		(524,527)
005027-AMORTIZATION OF ACCOUNT 114		(22,723)
005028-OREGON OPER PROPERTY TAX ADJ		(46,046)
005033-NONVEBA PEN&BEN-Acct 228		(226,912)
005035-PCA EXPENSE DEFERRAL		69,409,536
005043-AMERICAN FALLS - FALLING WATER CONTRACT-FT		219,181
005047-OTHER EMPLOYEE'S LT DEFERRED COMP-228		538,704
005052-AMORTIZATION OF ACCOUNT 181		146,153
005053-STOCK BASED COMPENSATION		(209,241)
005054-IPUC GRID WEST LOANS-ACCT 182		186,435
005055-OPUC GRID WEST LOANS-ACCT 182		(4,757)
005056-FERC GRID WEST EXP-ACCT 182		83,796
005057-INTERVENER FUNDING ORDERS-ACCT 182		(11,726)
005058-FIXED COST ADJUSTMENT (FCA)-ACCT 182		(6,219,265)
005059-PS & I COSTS-COAL & CHP PLANTS-WRITE OFF		88,689
005060-OREGON-PCAM (POWER COST ADJ MECHANISM)		(85,762)
005061-PENSION EXPENSE-OREGON		1,206,251
005501-SEC PLAN-NET INS COSTS		(281,520)
005503-128-EDC-UNRLZD GN/LS FRM RABBI TRUST		(518,785)
005504-NONDEDUCTIBLE POLITICAL EXP-426.4		1,050,861
005505-SEC PLAN-BENEFIT ACCR		2,061,539
005516-NONDEDUCTIBLE POLITICAL EXP-O&M ACCTS		100,000
005531-RATE CASE DISALLOWANCES-REVERSE AMORT		(296,299)
005532-DELIVERY ACCRUALS-253.550		(80,907)
Total	$	89,802,330

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

007009-PROVISION FOR RATE REFUNDS-ACCT 229	$	13,344,853
007010-AFUDC HC RELICENSING-ACCT 229		(9,894,077)

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	04/12/2010	2009/Q4

FOOTNOTE DATA

007011-OATT REVENUE DEFICIENCY		1,761,114
007501-REVERSE EQUITY EARNINGS OF SUBSIDIARIES		4,957,254
007502-ALLOWANCE FOR OFUDC		7,554,922
007503-ALLOWANCE FOR BFUDC		5,397,871
007504-RECLASS TAX EXEMPT INTEREST-FED ONLY		4,717
007509-SECURITY PLAN-INSURANCE PROCEEDS		1,943,416
Total	$	25,070,070

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

008001-VEBA-POST RET BNFTS-TRUST-ACCT 228	$	(1,615,820)
008009-DEPR FOR TAX GT OR LT BOOK		47,115,386
008016-VEBA-POST RET BNFTS-TRUST-MEDICARE PART D		703,000
008020-CONSERVATION PROGRAMS		3,400,368
008025-MANUFACTURING DEDUCTION		4,086,963
008027-NEVADA OPERATING PROPERTY TAX ADJ		89,475
008034-REMOVAL COSTS		10,884,841
008035-REPAIR ALLOWANCE		10,000,000
008038-OREGON EXCESS PWR SUPPLY COSTS		5,089,767
008041-AM FALLS - UNAMORTIZED DEBT EXP		(47,999)
008042-GAIN/LOSS ON REACQUIRED DEBT-FT		2,598,905
008057-REORGANIZATION COSTS		1,145,203
008059-SFTWR COSTS-MISC-107-FED ONLY		1,000,000
008072-INTANGIBLE ASSET-LABOR DEDUCT-107-FED ONLY		1,108,000
008077-PP INS & OTR EXP (1 YR OR LESS)-165		1,279,624
008501-COLI-TAX ADJ FROM BOOKS		2,442,758
008504-OREGON NONOP PROPERTY TAX ADJUST		12
008703-IPCO - 162 (M) $1m THRESHOLD		(775,671)
0NI0016-DIV PAID DED PUB UTIL		300,000
IRS INTEREST EXPENSE		249,457
STATE INCOME TAX DEDUCTED ON FEDERAL RETURN		5,993,036
Total	$	95,047,305

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	04/12/2010	End of 2009/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	BALANCE AT BEGINNING OF YEAR Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	Federal:					
2	Income	-44,279,599		19,534,398	-19,542,121	
3	Social Security - (FOAB)	409		12,208,440	12,206,314	-411
4	Unemployment	-36		75,819	75,819	36
5	Subtotal Federal	-44,279,226		31,818,657	-7,259,988	-375
6						
7	State of Idaho:					
8	Property	4,978,404	-75	12,633,142	11,947,458	
9	Non-Operating	14,996		32,911	26,041	
10	Income	-3,798,000		2,113,920	2,894,446	
11	KWH	95,195		1,849,144	1,825,157	
12	Unemployment	6,204		466,050	492,204	19,947
13	Regulatory Commission			1,347,232	1,347,232	
14	Business License - Sho Ban		150	150	150	
15	Subtotal Idaho	1,296,799	75	18,442,549	18,532,688	19,947
16						
17	State of Oregon					
18	Property		1,044,661	2,136,606	2,182,652	
19	Non-Operating Property		754	1,521	1,533	
20	Income	-212,449		169,976	219,082	
21	Regulatory Commission			118,625	97,325	
22	Unemployment	-14		15,877	15,877	21
23	Franchise	137,706		610,826	587,639	
24	Subtotal Oregon	-74,757	1,045,415	3,053,431	3,104,108	21
25						
26	State of Montana:					
27	Property	99,130		238,460	218,442	
28	Subtotal Montana	99,130		238,460	218,442	
29						
30	State of Nevada:					
31	Property		443,859	1,003,360	1,092,835	
32	Business Tax			100	100	
33	Subtotal Nevada		443,859	1,003,460	1,092,935	
34						
35	State of Wyoming					
36	Corporate License			3,387	3,387	
37	Property	513,670		1,128,204	1,077,771	
38	Subtotal Wyoming	513,670		1,131,591	1,081,158	
39	Other States Income	31,734		64,710	-10,351	
40	Payroll Adjustment			-12,766,186		
41	TOTAL	-42,412,650	1,489,349	42,986,672	16,758,992	19,593

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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
-5,203,080		18,051,943			1,482,455	2
2,124		12,208,440				3
		75,819				4
-5,200,956		30,336,202			1,482,455	5
						6
						7
5,673,820	225	12,633,142				8
21,866					32,911	9
-4,578,526		1,816,273			297,647	10
119,182		1,849,144				11
-3		466,050				12
		1,347,232				13
	150	150				14
1,236,339	375	18,111,991			330,558	15
						16
						17
	1,090,708	2,136,606				18
	766				1,521	19
-261,555		156,173			13,803	20
21,300		118,625				21
7		15,877				22
160,894		610,826				23
-79,354	1,091,474	3,038,107			15,324	24
						25
						26
119,148		238,460				27
119,148		238,460				28
						29
						30
	533,334	1,003,360				31
		100				32
	533,334	1,003,460				33
						34
						35
		3,387				36
564,102		1,128,204				37
564,102		1,131,591				38
106,794		59,876			4,834	39
		-12,766,186				40
-3,253,927	1,625,183	41,153,501			1,833,171	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 2009 this cross-check will not work as the total of lines 14-16 on page 114 is $2,981,574 more 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 of the entry is not associated with accounts 236 or 165. Therefore FIN #48 will show up on page 114 but will not be on pages 262& 263.

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

```
Account   409.2      $ 1,681,539
          237            (10,429)
          234           (188,655)
                     ------------
Total                $ 1,482,455
                     ============
```

Schedule Page: 262 Line No.: 3 Column: f

Entry was to clear up an adjustment which was the result of a change in rates.

Schedule Page: 262 Line No.: 4 Column: f

Entry is to clear up adjustment that was the result of a change in the rates.

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

```
Account 408.2        $  32,911
```

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

```
Account   409.2      $  331,587
          234           (33,940)
                     -----------
Total                $  297,647
                     ===========
```

Schedule Page: 262 Line No.: 12 Column: f

This amount represents an adjustment as a result of changes in the unemployment tax rates.

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

```
Account   408.2      $    1,521
```

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

```
Account   409.2      $   15,529
          234            (1,726)
                     -----------
Total                $   13,803
                     ==========
```

Schedule Page: 262 Line No.: 22 Column: f

This amount represents an adjustment for a change in unemployment tax rates for the year.

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

```
Account   409.2      $    5,409
          234              (575)
                     ----------
                     $    4,834
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	04/12/2010	End of 2009/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%	941,495				115,937	
4	7%						
5	10%	28,723,886				1,621,556	
6		1,320,423				26,722	
7		42,284,273	411.4	3,639,767	411.4	1,640,104	
8	TOTAL	73,270,077		3,639,767		3,404,319	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Line 6 Col A 11%						
11							
12	State of Idaho	42,284,273	411.4	3,639,767	411.4	1,640,104	
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
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42							
43							
44							
45							
46							
47							
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
825,558			3
			4
27,102,330			5
1,293,701			6
44,283,936			7
73,505,525			8
			9
			10
			11
44,283,936			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
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			31
			32
			33
			34
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			47
			48

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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) 04/12/2010	Year/Period of Report End of 2009/Q4

OTHER DEFFERED CREDITS (Account 253)

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

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Bureau of Land Mngt Rents/ROW	10,675,631	107/403	10,675,631		
2						
3	Point to Point Transmission Study	2,436,253	various	1,814,044	1,118,896	1,741,105
4						
5	FTV	5,266,666	400	400,000		4,866,666
6						
7	SWIP Deposit	940,000	186/4211	1,880,000	940,000	
8						
9	Sho Ban Trans ROW	292,500	242	15,000	100,650	378,150
10						
11	Delivery Accruals	198,964	107/401	1,147,396	1,045,495	97,063
12						
13	Customer Level Pay	1,054,504	142	2,146,318	1,091,814	
14						
15	Milner Falling Water	2,386,417	186	1,063,636	539,109	1,861,890
16						
17	Postretirement Benefits	2,671,584			1,844,942	4,516,526
18						
19	Directors Deferred Compensation	3,976,684	various	288,729	641,968	4,329,923
20						
21	IBM Mainframe Software Longterm				1,514,798	1,514,798
22						
23	Minor Items (4)	39,932	various	29,817	47,035	57,150
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	29,939,135		19,460,571	8,884,707	19,363,271

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	04/12/2010	End of 2009/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	246,423,677	55,807,604	20,197,518
3	Gas			
4	Other			
5	TOTAL (Enter Total of lines 2 thru 4)	246,423,677	55,807,604	20,197,518
6	Non-Operating Property			
7	Other - Regulatory Asset for I	333,882,360		
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	580,306,037	55,807,604	20,197,518
10	Classification of TOTAL			
11	Federal Income Tax	490,549,187	55,540,671	20,185,357
12	State Income Tax	89,756,850	266,933	12,161
13	Local Income Tax			

NOTES

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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
						282,033,763	2
							3
							4
						282,033,763	5
							6
		182	6,012,913	182	54,266,530	382,135,977	7
							8
			6,012,913		54,266,530	664,169,740	9
[redacted]							10
			4,954,340		37,534,439	558,484,600	11
			1,058,573		16,732,091	105,685,140	12
							13

NOTES (Continued)

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

Line No.	Account (a)	2009 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	Adj Dr Acct. Cr. g	Amt h	Adj Cr Acct. Dr. i	Amt j	2009 Ending Balance k
Line 2:	Accelerated Depreciation	238,722,106	51,016,405	20,069,733							269,668,778
	Intg Asset-Labor Ded	12,890,324	139,329								13,029,653
	Valmy Capitalized Items	580,766		76,500							504,266
	Bridger Capitalized Items	17,657		17,657							0
	Eng Fees in Acct 107	(286,041)	178,932	26,332							(133,441)
	Misc Software Dev Costs	494,627	(129,304)								365,323
	Taxable CIAC in CWIP	(5,995,762)	4,602,242	7,296							(1,400,816)
	TOTAL Line 2	246,423,677	55,807,604	20,197,518							282,033,763

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	04/12/2010	End of 2009/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	62,718,244	9,904,385	30,127,894
4				
5				
6				
7				
8	Other -- See Note	[redacted]		
9	TOTAL Electric (Total of lines 3 thru 8)	132,052,498	9,904,385	30,127,894
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other -- See Note	[redacted]		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	131,902,154	9,904,385	30,127,894
20	Classification of TOTAL			
21	Federal Income Tax	110,646,659	8,308,334	25,272,907
22	State Income Tax	21,255,495	1,596,051	4,854,987
23	Local Income Tax			

NOTES

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/Q4

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

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

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
[redacted]							1
							2
						42,494,735	3
							4
							5
							6
							7
			3,644,718		1,168,596	66,858,132	8
			3,644,718		1,168,596	109,352,867	9
[redacted]							10
							11
							12
							13
							14
							15
							16
							17
248,935	39,095					59,496	18
248,935	39,095		3,644,718		1,168,596	109,412,363	19
[redacted]							20
208,820	32,795		3,057,387		980,307	91,781,031	21
40,115	6,300		587,331		188,289	17,631,332	22
							23

NOTES (Continued)

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) 04/12/2010	2009/Q4

FOOTNOTE DATA

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

Account (a)	2009 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	Adj Dr Acct. Cr g	Amount h	Adj Cr Acct. Dr i	Amount j	2009 Ending Balance k
PCA Expense Deferral	56,054,006	0	28,135,644							27,918,362
Conservation Programs	1,901,555	3,677,967	807,343							4,772,179
Oregon Excess Pwr Costs	1,540,774	2,512,547	938,335							3,114,986
Oregon PCAM	2,110,996	127,253	93,725							2,144,524
IPUC Grid West Loans	218,661	0	72,887							145,774
OATT Revenue Deficiency	0	688,508	0							688,508
Reorganization Costs	0	447,717	0							447,717
FERC Grid West Expense	141,961	0	32,760							109,201
OPUC Grid West Loans	25,410	1,860	0							27,269
Intervenor Funding Orders	30,223	17,112	12,527							34,808
Fixed Cost Adjustment	631,947	2,431,421	0							3,063,368
PS & I Costs-Coal & CHP	62,712	0	34,673							28,039
TOTAL	62,718,244	9,904,385	30,127,894	0	0		0		0	42,494,735

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

Pension	61,943,745					190	2,245,207	190		59,698,538
Postretirement Plan	7,390,494					190	1,399,511	190		5,990,982
Unrealized gains on Mkt Sec	15					219		219	1,168,596	1,168,611
TOTAL	69,334,254	0	0	0	0		3,644,718		1,168,596	66,858,132

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

Advance Coal Royalties	239,738			46,111	39,095					246,755
Ore Non-Op Prop Tax Adj	295			5	0					299
Unrealized G/LRabbi Trust	(390,377)			202,819	0					(187,558)
TOTAL	(150,344)	0	0	248,935	39,095		0		0	59,496

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Market to Market Short Term - IPUC Order #28661	652,080	175	4,101,274	3,951,863	502,669
2						
3	Demand Side Management Rider OR	196,827	various	2,579,082	2,382,255	
4						
5	FAS 133 - Market to Market - IPUC Order # 28661		175	485,073	697,653	212,580
6						
7	Fixed Cost Adjustment- Prior Yr Def	1,104,779	4074	1,104,779		
8						
9	Emission Sales IEEP- Order #30529	500,000	various	57,990	37,091	479,101
10						
11	Unfunded Accumulated Deferred Income Tax	44,340,913	various	659,658	3,502,039	47,183,294
12						
13	Asset Retirement Oblication - Removal Cost	156,837,476	108	158,723,495	1,886,019	
14						
15	FERC Credit for OFA - IPUC Order #30754		401	620,808	1,707,209	1,086,401
16						
17						
18	Minor Items (11)	16,032	various	86,596,183	86,594,185	14,034
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	203,648,107		254,928,342	100,758,314	49,478,079

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	04/12/2010	End of 2009/Q4

ELECTRIC OPERATING REVENUES (Account 400)

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

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	409,479,319	353,261,718
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	339,240,028	305,854,293
5	Large (or Ind.) (See Instr. 4)	141,529,986	122,302,388
6	(444) Public Street and Highway Lighting	3,230,165	2,892,343
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	893,479,498	784,310,742
11	(447) Sales for Resale	94,373,321	121,428,825
12	TOTAL Sales of Electricity	987,852,819	905,739,567
13	(Less) (449.1) Provision for Rate Refunds	-2,551,647	9,979,836
14	TOTAL Revenues Net of Prov. for Refunds	990,404,466	895,759,731
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	3,811,350	3,669,976
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	18,272,233	18,889,639
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	32,457,459	19,432,928
22	(456.1) Revenues from Transmission of Electricity of Others	1,050,873	18,323,290
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	55,591,915	60,315,833
27	TOTAL Electric Operating Revenues	1,045,996,381	956,075,564

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/Q4

ELECTRIC OPERATING REVENUES (Account 400)

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

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
5,300,443	5,297,257	405,144	402,520	2
				3
5,476,690	5,860,422	81,532	80,636	4
3,140,209	3,355,202	127	122	5
30,938	30,833	1,372	1,257	6
				7
				8
				9
13,948,280	14,543,714	488,175	484,535	10
2,836,028	2,048,233			11
16,784,308	16,591,947	488,175	484,535	12
				13
16,784,308	16,591,947	488,175	484,535	14

Line 12, column (b) includes $ 6,736,815 of unbilled revenues.

Line 12, column (d) includes 40 MWH relating to unbilled revenues

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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) 04/12/2010	Year/Period of Report End of 2009/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	5,286,525	397,719,732	404,997	13,053	0.0752
3	03 - Residential Master Meter	3,144	236,262	17	184,941	0.0751
4	04 - Residential - EW	832	61,084	51	16,314	0.0734
5	05 - Residential - TOD	1,221	89,978	79	15,456	0.0737
6	15 - Dusk to dawn lighting	2,839	503,511			0.1774
7	Unbilled Revenues	5,882	3,922,007			0.6668
8	Other Revenues		6,946,745			
9	Total 440	5,300,443	409,479,319	405,144	13,083	0.0773
10						
11	442-Commercial & Industrial Sales					
12	07 - General service	175,670	16,032,609	31,727	5,537	0.0913
13	09 - General service	397,217	21,425,439	169	2,350,396	0.0539
14	09 - General service	3,241,472	188,932,352	29,730	109,030	0.0583
15	09 - General service	4,610	236,061	3	1,536,667	0.0512
16	15 - Dusk to Dawn Light	4,174	673,225			0.1613
17	19 - Uniform rate contracts	2,097,012	96,617,388	119	17,621,950	0.0461
18	19 - Uniform rate contracts	7,632	388,699	1	7,632,000	0.0509
19	19 - Uniform rate contracts	121,091	5,066,614	4	30,272,750	0.0418
20	24 - Irrigation Pumping	1,649,757	109,433,627	18,753	87,973	0.0663
21	40 - General service	13,773	948,433	1,153	11,945	0.0689
22	Commercial & Industrial & Unbill	904,491	40,056,593			0.0443
23	Other Revenues		958,974			
24	Total 442	8,616,899	480,770,014	81,659	105,523	0.0558
25						
26	444 - Public Street Lighting:					
27	40 - General service	2,765	190,561	783	3,531	0.0689
28	41 - Street lighting	23,902	2,779,466	275	86,916	0.1163
29	42 - Traffic control lighting	3,937	198,690	314	12,538	0.0505
30	Other Revenues	334	61,448			0.1840
31	Total 444	30,938	3,230,165	1,372	22,550	0.1044
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	13,948,240	886,742,683	488,175	28,572	0.0636
42	Total Unbilled Rev.(See Instr. 6)	40	6,736,815	0	0	168.4204
43	TOTAL	13,948,280	893,479,498	488,175	28,572	0.0641

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	04/12/2010	End of 2009/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	Raft River Rural Electric	RQ	V6-44	9.098	9.098	8.288
2	Raft River Rural Electric	RQ	V6-44	n/a	n/a	n/a
3						
4						
5	Arizona Public Service Co.	SF	WSPP	n/a	n/a	n/a
6	Avista Corp.	OS	WSPP	n/a	n/a	n/a
7	Avista Corp.	SF	WSPP	n/a	n/a	n/a
8	Barclays Bank PLC	SF	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.	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	OS	WSPP	n/a	n/a	n/a
14	Bonneville Power Administration	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) 04/12/2010	Year/Period of Report End of 2009/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.
55,078	695,552	1,823,133	6,000	2,524,685	1
			178,639	178,639	2
					3
					4
251,589		4,858,079		4,858,079	5
1,955		28,495		28,495	6
9,115		247,278		247,278	7
49,250		1,888,240		1,888,240	8
			502	502	9
44,541		1,111,941		1,111,941	10
2,470		55,207		55,207	11
7,800		234,300		234,300	12
275		5,275		5,275	13
68,357		1,897,699		1,897,699	14
55,078	695,552	1,823,133	184,639	2,703,324	
2,780,950	0	89,082,078	2,587,919	91,669,997	
2,836,028	**695,552**	**90,905,211**	**2,772,558**	**94,373,321**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/Q4

SALES FOR RESALE (Account 447)

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	BP Energy Company	SF	WSPP	n/a	n/a	n/a
2	Cargill Power Markets LLC	OS	WSPP	n/a	n/a	n/a
3	Cargill Power Markets LLC	OS	WSPP	n/a	n/a	n/a
4	Cargill Power Markets LLC	SF	WSPP	n/a	n/a	n/a
5	Chelan Co PUD	SF	WSPP	n/a	n/a	n/a
6	Citigroup Energy Inc.	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,	AD	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	DB Energy Trading LLC	SF	WSPP	n/a	n/a	n/a
12	El Paso Electric Company	SF	WSPP	n/a	n/a	n/a
13	Endure Energy, LLC	OS	WSPP	n/a	n/a	n/a
14	Endure Energy, LLC	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) 04/12/2010	Year/Period of Report End of 2009/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.
86,775		3,740,260		3,740,260	1
			610,781	610,781	2
225		4,050		4,050	3
190,771		5,403,639		5,403,639	4
200		7,000		7,000	5
116,600		3,895,230		3,895,230	6
9,400		377,320		377,320	7
57		-4,471		-4,471	8
5,317		136,389		136,389	9
125,401		5,135,360		5,135,360	10
14,200		420,528		420,528	11
2,400		61,000		61,000	12
			12,775	12,775	13
270		2,160		2,160	14
55,078	695,552	1,823,133	184,639	2,703,324	
2,780,950	0	89,082,078	2,587,919	91,669,997	
2,836,028	**695,552**	**90,905,211**	**2,772,558**	**94,373,321**	

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	04/12/2010	End of 2009/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	Endure Energy, LLC	SF	WSPP	n/a	n/a	n/a
2	Eugene Electric Board	SF	WSPP	n/a	n/a	n/a
3	Grant CO Public Utility District #2 --	SF	WSPP	n/a	n/a	n/a
4	IBERDROLA RENEWABLES, Inc.	OS	WSPP	n/a	n/a	n/a
5	IBERDROLA RENEWABLES, Inc.	OS	WSPP	n/a	n/a	n/a
6	IBERDROLA RENEWABLES, Inc.	SF	WSPP	n/a	n/a	n/a
7	Integrys Energy Services, Inc.	OS	WSPP	n/a	n/a	n/a
8	Integrys Energy Services, Inc.	SF	WSPP	n/a	n/a	n/a
9	J. Aron & Company	SF	WSPP	n/a	n/a	n/a
10	J.P. Morgan Ventures Energy Corporation	SF	WSPP	n/a	n/a	n/a
11	Macquarie Cook Power Inc.	SF	WSPP	n/a	n/a	n/a
12	Morgan Stanley Capital Group Inc.	OS	WSPP	n/a	n/a	n/a
13	Morgan Stanley Capital Group Inc.	OS	-	n/a	n/a	n/a
14	Morgan Stanley Capital Group Inc.	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	04/12/2010	End of 2009/Q4

SALES FOR RESALE (Account 447) (Continued)

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

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

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

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

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

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

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

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

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
3,200		69,600		69,600	1
400		20,400		20,400	2
4,000		140,292		140,292	3
			11,209	11,209	4
2,629		48,774		48,774	5
139,452		4,756,695		4,756,695	6
175		3,325		3,325	7
51,216		2,322,004		2,322,004	8
30,400		2,090,000		2,090,000	9
28,400		1,148,412		1,148,412	10
14,025		461,740		461,740	11
			20,640	20,640	12
		37,252		37,252	13
200,000		5,645,504		5,645,504	14
55,078	695,552	1,823,133	184,639	2,703,324	
2,780,950	0	89,082,078	2,587,919	91,669,997	
2,836,028	**695,552**	**90,905,211**	**2,772,558**	**94,373,321**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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	NextEra Energy Power Marketing, LLC	SF	WSPP	n/a	n/a	n/a
2	NorthPoint Energy Solutions Inc.	SF	WSPP	n/a	n/a	n/a
3	NorthWestern Energy	AD	WSPP	n/a	n/a	n/a
4	NorthWestern Energy	OS	WSPP	n/a	n/a	n/a
5	NorthWestern Energy	SF	WSPP	n/a	n/a	n/a
6	PacifiCorp Inc.	SF	T-7	n/a	n/a	n/a
7	PacifiCorp Inc.	OS	WSPP	n/a	n/a	n/a
8	PacifiCorp Inc.	OS	WSPP	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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/12/2010	End of 2009/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.
15,600		390,000		390,000	1
100		2,600		2,600	2
			-181	-181	3
			69	69	4
290		7,960		7,960	5
72		2,535		2,535	6
			1,293,778	1,293,778	7
4,600		61,425		61,425	8
21,553		758,204		758,204	9
			12,506	12,506	10
16,804		496,782		496,782	11
15,513		419,701		419,701	12
			388,652	388,652	13
172,550		2,314,146		2,314,146	14
55,078	695,552	1,823,133	184,639	2,703,324	
2,780,950	0	89,082,078	2,587,919	91,669,997	
2,836,028	**695,552**	**90,905,211**	**2,772,558**	**94,373,321**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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	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	Prudential Bache Commodities, LLC	OS	-	n/a	n/a	n/a
6	Public Service Company of Colorado	SF	WSPP	n/a	n/a	n/a
7	Public Service Company of New Mexico	SF	WSPP	n/a	n/a	n/a
8	Puget Sound Energy, Inc.	SF	T-7	n/a	n/a	n/a
9	Puget Sound Energy, Inc.	OS	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	Seattle City Light	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) 04/12/2010	Year/Period of Report End of 2009/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.
194,829		8,463,278		8,463,278	1
			31,179	31,179	2
2,262		25,409		25,409	3
30,913		990,309		990,309	4
		769,441		769,441	5
2,400		64,200		64,200	6
1,600		47,200		47,200	7
9		170		170	8
37,808		636,851		636,851	9
54,914		1,903,926		1,903,926	10
5,600		116,800		116,800	11
			34,650	34,650	12
294,218		7,430,696		7,430,696	13
15,567		297,964		297,964	14
55,078	695,552	1,823,133	184,639	2,703,324	
2,780,950	0	89,082,078	2,587,919	91,669,997	
2,836,028	**695,552**	**90,905,211**	**2,772,558**	**94,373,321**	

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	04/12/2010	End of 2009/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	Actual Demand (MW) 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 Trading LLC	OS	-	n/a	n/a	n/a
3	Sempra Energy Trading LLC	SF	WSPP	n/a	n/a	n/a
4	Shell Energy North America (US), L.P.	OS	WSPP	n/a	n/a	n/a
5	Shell Energy North America (US), L.P.	OS	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.	SF	WSPP	n/a	n/a	n/a
8	Sierra Pacific Power Co., dba NV Energy	SF	T-7	n/a	n/a	n/a
9	Sierra Pacific Power Co., dba NV Energy	OS	WSPP	n/a	n/a	n/a
10	Sierra Pacific Power Co., dba NV Energy	OS	WSPP	n/a	n/a	n/a
11	Sierra Pacific Power Co., dba NV Energy	SF	WSPP	n/a	n/a	n/a
12	Snohomish County PUD	OS	WSPP	n/a	n/a	n/a
13	Snohomish County PUD	SF	WSPP	n/a	n/a	n/a
14	The Energy Authority, Inc.	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) 04/12/2010	Year/Period of Report End of 2009/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.
8,407		196,770		196,770	1
		1,223,044		1,223,044	2
138,400		8,157,816		8,157,816	3
12,298		363,305		363,305	4
			32,888	32,888	5
88,501		1,745,192		1,745,192	6
103,879		2,977,505		2,977,505	7
93		3,151		3,151	8
			128,754	128,754	9
43		430		430	10
100		2,000		2,000	11
460		7,610		7,610	12
1,100		28,180		28,180	13
2		46		46	14
55,078	695,552	1,823,133	184,639	2,703,324	
2,780,950	0	89,082,078	2,587,919	91,669,997	
2,836,028	**695,552**	**90,905,211**	**2,772,558**	**94,373,321**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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	TransAlta Energy Marketing (U.S.) Inc.	OS	WSPP	n/a	n/a	n/a
2	TransAlta Energy Marketing (U.S.) Inc.	SF	WSPP	n/a	n/a	n/a
3	UBS Securities LLC	OS	-	n/a	n/a	n/a
4	United Materials of Great Falls	LF	61	n/a	n/a	n/a
5						
6						
7						
8						
9						
10						
11						
12	LESS BAD DEBT WRITE-OFF					
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/12/2010	End of 2009/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.
			9,717	9,717	1
79,600		2,093,582		2,093,582	2
		810,060		810,060	3
		24,814		24,814	4
					5
					6
					7
					8
					9
					10
					11
		-1		-1	12
					13
					14
55,078	695,552	1,823,133	184,639	2,703,324	
2,780,950	0	89,082,078	2,587,919	91,669,997	
2,836,028	**695,552**	**90,905,211**	**2,772,558**	**94,373,321**	

Schedule Page: 310 Line No.: 1 Column: b
Customer Charge
Schedule Page: 310 Line No.: 2 Column: b
Network Transmission Charges
Schedule Page: 310 Line No.: 6 Column: b
Non-firm Sales
Schedule Page: 310 Line No.: 9 Column: b
Financial Transmission Losses
Schedule Page: 310 Line No.: 10 Column: b
Non-firm Sales
Schedule Page: 310 Line No.: 12 Column: b
Unit Contingent
Schedule Page: 310 Line No.: 13 Column: b
Non-firm Sales
Schedule Page: 310.1 Line No.: 2 Column: b
Financial Transmission Losses
Schedule Page: 310.1 Line No.: 3 Column: b
Non-firm Sales
Schedule Page: 310.1 Line No.: 8 Column: b
2008 Correction
Schedule Page: 310.1 Line No.: 9 Column: b
Non-firm Sales
Schedule Page: 310.1 Line No.: 13 Column: b
Financial Transmission Losses
Schedule Page: 310.1 Line No.: 14 Column: b
Non-firm Sales
Schedule Page: 310.2 Line No.: 4 Column: b
Financial Transmission Losses
Schedule Page: 310.2 Line No.: 5 Column: b
Non-firm Sales
Schedule Page: 310.2 Line No.: 7 Column: b
Non-firm Sales
Schedule Page: 310.2 Line No.: 12 Column: b
Financial Transmission Losses
Schedule Page: 310.2 Line No.: 13 Column: b
ISDA Master Agreement with Morgan Stanley dated March 1, 2000
Schedule Page: 310.3 Line No.: 3 Column: b
2008 Financial Transmission Loss Correction
Schedule Page: 310.3 Line No.: 4 Column: b
Financial Transmission Losses
Schedule Page: 310.3 Line No.: 7 Column: b
Financial Transmission Losses
Schedule Page: 310.3 Line No.: 8 Column: b
Non-firm Sales
Schedule Page: 310.3 Line No.: 10 Column: b
Financial Transmission Losses
Schedule Page: 310.3 Line No.: 11 Column: b
Non-firm Sales
Schedule Page: 310.3 Line No.: 13 Column: b
Financial Transmission Losses
Schedule Page: 310.3 Line No.: 14 Column: b
Non-firm Sales
Schedule Page: 310.4 Line No.: 2 Column: b
Financial Transmission Losses

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	04/12/2010	2009/Q4

FOOTNOTE DATA

Schedule Page: 310.4 Line No.: 3 Column: b

Non-firm Sales

Schedule Page: 310.4 Line No.: 5 Column: b

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

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

Non-firm Sales

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

Unit Contingent

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

Financial Transmission Losses

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

Non-firm Sales

Schedule Page: 310.5 Line No.: 2 Column: b

ISDA Master Agreement with Sempra dated February 21, 2008.

Schedule Page: 310.5 Line No.: 4 Column: b

Unit Contingent

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

Financial Transmission Losses

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

Non-firm Sales

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

Financial Transmission Losses

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

Non-firm Sales

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

Non-firm Sales

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

Financial Transmission Losses

Schedule Page: 310.6 Line No.: 3 Column: b

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

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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	1,814,867	1,650,283
5	(501) Fuel	130,234,531	132,015,165
6	(502) Steam Expenses	7,434,710	7,376,689
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	2,568,382	1,817,960
10	(506) Miscellaneous Steam Power Expenses	8,111,562	7,737,497
11	(507) Rents	514,732	469,699
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	150,678,784	151,067,293
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	2,072,391	2,567,722
16	(511) Maintenance of Structures	487,528	398,714
17	(512) Maintenance of Boiler Plant	13,675,892	14,205,043
18	(513) Maintenance of Electric Plant	3,595,301	4,301,150
19	(514) Maintenance of Miscellaneous Steam Plant	4,639,081	4,322,931
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	24,470,193	25,795,560
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	175,148,977	176,862,853
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	5,242,496	5,602,490
45	(536) Water for Power	7,174,597	7,355,741
46	(537) Hydraulic Expenses	10,093,906	9,978,475
47	(538) Electric Expenses	1,470,715	1,312,586
48	(539) Miscellaneous Hydraulic Power Generation Expenses	2,686,753	3,091,676
49	(540) Rents	376,849	431,893
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	27,045,316	27,772,861
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	2,072,103	1,885,154
54	(542) Maintenance of Structures	1,396,815	1,362,031
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,132,574	808,311
56	(544) Maintenance of Electric Plant	2,962,850	2,495,503
57	(545) Maintenance of Miscellaneous Hydraulic Plant	2,971,583	3,135,803
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	10,535,925	9,686,802
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	37,581,241	37,459,663

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	04/12/2010	End of 2009/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	347,933	372,614
63	(547) Fuel	19,331,689	17,387,509
64	(548) Generation Expenses	405,013	404,456
65	(549) Miscellaneous Other Power Generation Expenses	320,014	530,176
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	20,404,649	18,694,755
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		213
70	(552) Maintenance of Structures	194,110	162,376
71	(553) Maintenance of Generating and Electric Plant	524,579	198,271
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	1,710,504	509,219
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	2,429,193	870,079
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	22,833,842	19,564,834
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	160,569,065	231,137,298
77	(556) System Control and Load Dispatching	13,142	77,979
78	(557) Other Expenses	69,383,801	-44,906,304
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	229,966,008	186,308,973
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	465,530,068	420,196,323
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,534,092	2,404,396
84	(561) Load Dispatching	169,190	87,197
85	(561.1) Load Dispatch-Reliability		1,517
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,348,929	1,635,606
87	(561.3) Load Dispatch-Transmission Service and Scheduling	994,682	1,069,383
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	101,790	90,292
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	1,946,068	1,805,491
94	(563) Overhead Lines Expenses	907,200	735,577
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	6,628,695	7,250,299
97	(566) Miscellaneous Transmission Expenses	386,603	465,343
98	(567) Rents	1,564,349	1,085,343
99	TOTAL Operation (Enter Total of lines 83 thru 98)	16,581,598	16,630,444
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	590,179	431,690
102	(569) Maintenance of Structures		
103	(569.1) Maintenance of Computer Hardware	82,703	98,395
104	(569.2) Maintenance of Computer Software	268,304	328,872
105	(569.3) Maintenance of Communication Equipment	32,141	24,333
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	2,999,666	2,706,580
108	(571) Maintenance of Overhead Lines	2,936,203	3,367,619
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	38	272
111	TOTAL Maintenance (Total of lines 101 thru 110)	6,909,234	6,957,761
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	23,490,832	23,588,205

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	04/12/2010	End of 2009/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	3,357,224	3,321,954
135	(581) Load Dispatching	3,186,033	3,110,301
136	(582) Station Expenses	1,136,350	1,143,619
137	(583) Overhead Line Expenses	3,446,690	3,346,471
138	(584) Underground Line Expenses	1,915,974	2,034,228
139	(585) Street Lighting and Signal System Expenses	134,828	130,886
140	(586) Meter Expenses	4,473,033	4,636,934
141	(587) Customer Installations Expenses	1,331,636	1,398,175
142	(588) Miscellaneous Expenses	5,003,459	5,464,167
143	(589) Rents	308,806	456,147
144	TOTAL Operation (Enter Total of lines 134 thru 143)	24,294,033	25,042,882
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	310,403	319,660
147	(591) Maintenance of Structures	25,089	2,323
148	(592) Maintenance of Station Equipment	3,354,447	3,534,603
149	(593) Maintenance of Overhead Lines	14,503,170	13,759,196
150	(594) Maintenance of Underground Lines	1,083,316	1,235,321
151	(595) Maintenance of Line Transformers	410,917	445,190
152	(596) Maintenance of Street Lighting and Signal Systems	501,683	665,088
153	(597) Maintenance of Meters	711,387	862,861
154	(598) Maintenance of Miscellaneous Distribution Plant	267,231	354,999
155	TOTAL Maintenance (Total of lines 146 thru 154)	21,167,643	21,179,241
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	45,461,676	46,222,123
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	373,734	341,842
160	(902) Meter Reading Expenses	5,399,410	5,752,965
161	(903) Customer Records and Collection Expenses	13,096,476	11,773,961
162	(904) Uncollectible Accounts	5,268,902	3,681,954
163	(905) Miscellaneous Customer Accounts Expenses	556	468
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	24,139,078	21,551,190

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	258,454	299,410
168	(908) Customer Assistance Expenses	40,754,937	27,674,740
169	(909) Informational and Instructional Expenses	16,116	
170	(910) Miscellaneous Customer Service and Informational Expenses	840,420	860,302
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	41,869,927	28,834,452
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	61,677,661	57,537,274
182	(921) Office Supplies and Expenses	12,455,430	14,791,345
183	(Less) (922) Administrative Expenses Transferred-Credit	27,866,621	22,736,029
184	(923) Outside Services Employed	7,562,948	13,597,223
185	(924) Property Insurance	3,262,112	3,103,669
186	(925) Injuries and Damages	6,804,103	7,548,140
187	(926) Employee Pensions and Benefits	31,049,314	22,840,421
188	(927) Franchise Requirements	3,196	1,549
189	(928) Regulatory Commission Expenses	5,298,808	4,832,197
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	158,199	236,828
192	(930.2) Miscellaneous General Expenses	3,561,160	3,515,410
193	(931) Rents	1,090	6,827
194	TOTAL Operation (Enter Total of lines 181 thru 193)	103,967,400	105,274,854
195	Maintenance		
196	(935) Maintenance of General Plant	3,946,638	4,149,187
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	107,914,038	109,424,041
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	708,405,619	649,816,334

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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 Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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)	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.
966				66,461		66,461	1
3,580				252,088		252,088	2
37,701			1,576,498	1,414,267		2,990,765	3
							4
5,316				113,344		113,344	5
19,128				334,358		334,358	6
8,364				811,912		811,912	7
1,447				104,835		104,835	8
326			17,500	9,191		26,691	9
385				25,910		25,910	10
726				48,582		48,582	11
615				34,355		34,355	12
1,564				110,379		110,379	13
510				34,358		34,358	14
2,911,842	195,389	327,800	2,815,124	153,627,912	4,126,029	160,569,065	

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					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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)	
1,218				26,209		26,209	1
627			26,796	17,751		44,547	2
770				52,942		52,942	3
							4
316				21,223		21,223	5
1,052				73,652		73,652	6
1,164				81,625		81,625	7
988				22,020		22,020	8
							9
1,876				148,497		148,497	10
2,334				157,088		157,088	11
8,126			552,508	229,728		782,236	12
							13
1,678				110,645		110,645	14
2,911,842	195,389	327,800	2,815,124	153,627,912	4,126,029	160,569,065	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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.

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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					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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.
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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)	
3,561				238,381		238,381	1
860				18,682		18,682	2
1,588				114,901		114,901	3
2,733			155,672	77,314		232,986	4
3,713				272,752		272,752	5
3,192				268,727		268,727	6
3,430				279,768		279,768	7
3,488				267,418		267,418	8
8,065				531,240		531,240	9
10,552				710,596		710,596	10
7,988			486,150	196,072		682,222	11
							12
3,265				239,439		239,439	13
11,578				593,225		593,225	14
2,911,842	195,389	327,800	2,815,124	153,627,912	4,126,029	160,569,065	

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	04/12/2010	End of 2009/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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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.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	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	Lemhi Hydro Power Co./Schaffner	LU	-	N/A	N/A	N/A
13	J R Simplot Co.	LU	-	N/A	N/A	N/A
14	Blind Canyon Hydro	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	04/12/2010	End of 2009/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.
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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)	
7,476				377,002		377,002	1
16,472				873,905		873,905	2
9,412				500,455		500,455	3
6,052				391,150		391,150	4
26,738				1,912,533		1,912,533	5
6,193				468,506		468,506	6
2,922				200,681		200,681	7
2,955				227,689		227,689	8
14,800				820,670		820,670	9
26,029				1,380,909		1,380,909	10
22,357				1,136,497		1,136,497	11
1,277				95,924		95,924	12
72,371				4,053,641		4,053,641	13
4,360				378,296		378,296	14
2,911,842	195,389	327,800	2,815,124	153,627,912	4,126,029	160,569,065	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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	City of Hailey	LU	-	N/A	N/A	N/A
2	City of Pocatello	LU	-	N/A	N/A	N/A
3	Marysville Hydro Partners/Falls River	LU	-	N/A	N/A	N/A
4	Wilson Power Company	LU	-	N/A	N/A	N/A
5	Hazelton B Power Company	LU	-	N/A	N/A	N/A
6	Pristine Springs Inc. #1	LU	-	N/A	N/A	N/A
7	Vaagen Brothers Lumber Inc.	LU	-	N/A	N/A	N/A
8	Horseshoe Bend Hydro	LU	-	N/A	N/A	N/A
9	Contractors Power Group Inc./Mile 28	LU	-	N/A	N/A	N/A
10	Rupert Cogeneration Partners/Magic Val	LU	-	N/A	N/A	N/A
11	Glenns Ferry Cogeneration Partners/Mag	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)	
39				2,725		2,725	1
1,377				96,436		96,436	2
54,227				3,488,938		3,488,938	3
25,128				1,742,986		1,742,986	4
21,783				1,509,013		1,509,013	5
787				36,261		36,261	6
15,888				992,596		992,596	7
43,451				2,965,894		2,965,894	8
4,371				288,254		288,254	9
80,630				5,134,610		5,134,610	10
42,844				3,129,312		3,129,312	11
1,498				35,507		35,507	12
1,171				56,531		56,531	13
29,331				1,419,455		1,419,455	14
2,911,842	195,389	327,800	2,815,124	153,627,912	4,126,029	160,569,065	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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 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	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	AD	-	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	Bennett Creek Wind Farm	LU		N/A	N/A	N/A
11	Bettencourt DryCreek Biofactory	LU		N/A	N/A	N/A
12	Big Sky Dairy Digester	LU		N/A	N/A	N/A
13	Hot Springs Wind Farm	LU		N/A	N/A	N/A
14	Cassia Gulch Wind Park	LU		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) 04/12/2010	Year/Period of Report End of 2009/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)	
26,353				1,276,619		1,276,619	1
21,356				993,751		993,751	2
17,406				818,893		818,893	3
				11,182		11,182	4
7							5
4,899				250,435		250,435	6
1,324				24,161		24,161	7
34,729				2,738,000		2,738,000	8
8,424				517,120		517,120	9
40,857				2,223,795		2,223,795	10
7,916				175,466		175,466	11
9,445				603,375		603,375	12
42,825				2,313,614		2,313,614	13
30,837				1,554,740		1,554,740	14
2,911,842	195,389	327,800	2,815,124	153,627,912	4,126,029	160,569,065	

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	04/12/2010	End of 2009/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	Cassia Wind Farm	LU		N/A	N/A	N/A
2	Other Purchased Power					
3	Arizona Public Service Co.	SF	WSPP	N/A	N/A	N/A
4	Avista Corp.	SF	T-12	N/A	N/A	N/A
5	Avista Corp.	SF	WSPP	N/A	N/A	N/A
6	Avista Corp.	OS	WSPP	N/A	N/A	N/A
7	Barclays Bank PLC	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.	SF	WSPP	N/A	N/A	N/A
10	Bonneville Power Administration	SF	WSPP	N/A	N/A	N/A
11	BP Energy Company	SF	WSPP	N/A	N/A	N/A
12	Cargill Power Markets LLC	SF	WSPP	N/A	N/A	N/A
13	Chelan Co PUD	SF	WSPP	N/A	N/A	N/A
14	Citigroup Energy Inc.	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.
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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)	
17,319				880,154		880,154	1
							2
47,706				1,797,625		1,797,625	3
54				1,922		1,922	4
8,635				227,561		227,561	5
					458,065	458,065	6
76,000				3,581,226		3,581,226	7
18,107				651,996		651,996	8
3,220				103,087		103,087	9
88,981				2,777,454		2,777,454	10
128,549				7,154,671		7,154,671	11
59,689				2,798,294		2,798,294	12
2,222				69,785		69,785	13
96,400				5,144,500		5,144,500	14
2,911,842	195,389	327,800	2,815,124	153,627,912	4,126,029	160,569,065	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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	Conoco Phillips Company	SF	WSPP	N/A	N/A	N/A
2	Constellation Energy Commodities Group	SF	WSPP	N/A	N/A	N/A
3	DB Energy Trading LLC	SF	WSPP	N/A	N/A	N/A
4	Douglas County PUD	SF	WSPP	N/A	N/A	N/A
5	El Paso Electric Company	SF	WSPP	N/A	N/A	N/A
6	Endure Energy, LLC	SF	WSPP	N/A	N/A	N/A
7	EPCOR Energy Marketing (U.S.) Inc.	SF	WSPP	N/A	N/A	N/A
8	Eugene Water & Electric Board	SF	WSPP	N/A	N/A	N/A
9	Fortis Energy Marketing & Trading GP	SF	WSPP	N/A	N/A	N/A
10	Grant CO Public Utility District #2 --	SF	WSPP	N/A	N/A	N/A
11	IBERDROLA RENEWABLES, Inc.	SF	WSPP	N/A	N/A	N/A
12	Integrys Energy Services, Inc.	SF	WSPP	N/A	N/A	N/A
13	J. Aron & Company	SF	WSPP	N/A	N/A	N/A
14	J.P. Morgan Ventures Energy Corporatio	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)	
2,600				86,000		86,000	1
935				26,792		26,792	2
14,200				390,246		390,246	3
1,202				27,902		27,902	4
312				14,175		14,175	5
4,800				144,500		144,500	6
97				2,960		2,960	7
800				25,000		25,000	8
2,800				107,536		107,536	9
1,765				59,726		59,726	10
86,926				4,626,826		4,626,826	11
68,165				2,652,657		2,652,657	12
2,400				108,020		108,020	13
23,650				1,291,508		1,291,508	14
2,911,842	195,389	327,800	2,815,124	153,627,912	4,126,029	160,569,065	

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	04/12/2010	End of 2009/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	Macquarie Cook Power Inc.	SF	WSPP	N/A	N/A	N/A
2	Morgan Stanley Capital Group Inc.	OS	-	N/A	N/A	N/A
3	Morgan Stanley Capital Group Inc.	SF	WSPP	N/A	N/A	N/A
4	NaturEner USA, LLC	SF	WSPP	N/A	N/A	N/A
5	Nevada Power Company, dba NV Energy	SF	WSPP	N/A	N/A	N/A
6	NextEra Energy Power Marketing, LLC	SF	WSPP	N/A	N/A	N/A
7	NorthWestern Energy	SF	T-7	N/A	N/A	N/A
8	NorthWestern Energy	SF	WSPP	N/A	N/A	N/A
9	PacifiCorp Inc.	SF	T-13	N/A	N/A	N/A
10	PacifiCorp Inc.	SF	WSPP	N/A	N/A	N/A
11	PacifiCorp Inc.	OS	WSPP	N/A	N/A	N/A
12	Portland General Electric Company	SF	T-14	N/A	N/A	N/A
13	Portland General Electric Company	SF	WSPP	N/A	N/A	N/A
14	Powerex Corp.	AD	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	04/12/2010	End of 2009/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)	
434				40,254		40,254	1
					335,936	335,936	2
52,573				2,662,898		2,662,898	3
1				66		66	4
125				3,125		3,125	5
16,400				668,300		668,300	6
83				3,021		3,021	7
950				28,255		28,255	8
485				17,455		17,455	9
36,770				1,255,554		1,255,554	10
					69,117	69,117	11
127				4,755		4,755	12
28,077				1,066,212		1,066,212	13
57				2,492		2,492	14
2,911,842	195,389	327,800	2,815,124	153,627,912	4,126,029	160,569,065	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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	Powerex Corp.	OS	WSPP	N/A	N/A	N/A
2	Powerex Corp.	SF	WSPP	N/A	N/A	N/A
3	PPL EnergyPlus, LLC	LF	WSPP	N/A	N/A	N/A
4	PPL EnergyPlus, LLC	OS	WSPP	N/A	N/A	N/A
5	PPL EnergyPlus, LLC	SF	WSPP	N/A	N/A	N/A
6	Prudential Bache Commodities, LLC	OS	-	N/A	N/A	N/A
7	Public Service Company of Colorado	SF	WSPP	N/A	N/A	N/A
8	Public Service Company of New Mexico	OS	WSPP	N/A	N/A	N/A
9	Public Service Company of New Mexico	SF	WSPP	N/A	N/A	N/A
10	Puget Sound Energy, Inc.	OS	WSPP	N/A	N/A	N/A
11	Puget Sound Energy, Inc.	SF	T-9	N/A	N/A	N/A
12	Puget Sound Energy, Inc.	SF	WSPP	N/A	N/A	N/A
13	Rainbow Energy Marketing Corporation	OS	WSPP	N/A	N/A	N/A
14	Rainbow Energy Marketing Corporation	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	04/12/2010	End of 2009/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
25				1,150		1,150	1
72,696				3,894,684		3,894,684	2
103,584				4,609,488		4,609,488	3
4,336				163,940		163,940	4
71,009				2,654,603		2,654,603	5
					2,047,770	2,047,770	6
308				14,008		14,008	7
					97,808	97,808	8
89				3,542		3,542	9
75				2,400		2,400	10
105				3,803		3,803	11
31,772				1,327,882		1,327,882	12
1,600				75,200		75,200	13
33,248				1,425,853		1,425,853	14
2,911,842	195,389	327,800	2,815,124	153,627,912	4,126,029	160,569,065	

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	04/12/2010	End of 2009/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	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 LLC	SF	WSPP	N/A	N/A	N/A
4	Shell Energy North America (US), L.P.	OS	WSPP	N/A	N/A	N/A
5	Shell Energy North America (US), L.P.	SF	WSPP	N/A	N/A	N/A
6	Sierra Pacific Power Co., dba NV Energ	SF	T-55	N/A	N/A	N/A
7	Sierra Pacific Power Co., dba NV Energ	SF	WSPP	N/A	N/A	N/A
8	Sierra Pacific Power Co., dba NV Energ	OS	WSPP	N/A	N/A	N/A
9	Snohomish County PUD	SF	WSPP	N/A	N/A	N/A
10	Southwestern Public Service Company	SF	WSPP	N/A	N/A	N/A
11	Tacoma Power	SF	WSPP	N/A	N/A	N/A
12	The Energy Authority, Inc.	SF	WSPP	N/A	N/A	N/A
13	TransAlta Energy Marketing (U.S.) Inc.	SF	WSPP	N/A	N/A	N/A
14	Tucson Electric Power 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) 04/12/2010	Year/Period of Report End of 2009/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)	
9,275				324,377		324,377	1
4,352				143,642		143,642	2
228,007				15,904,975		15,904,975	3
4,635				129,780		129,780	4
23,344				796,846		796,846	5
68				2,584		2,584	6
6,212				193,934		193,934	7
					18,573	18,573	8
9,484				289,773		289,773	9
7				35		35	10
7,767				197,638		197,638	11
7,245				212,814		212,814	12
71,681				5,849,167		5,849,167	13
1,133				36,577		36,577	14
2,911,842	195,389	327,800	2,815,124	153,627,912	4,126,029	160,569,065	

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	04/12/2010	End of 2009/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.

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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.

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	UBS Securities LLC	OS	-	N/A	N/A	N/A
2	Raft River Energy I LLC	LU	-	N/A	N/A	N/A
3	Telocaset Wind Power Partners LLC	LU	APP-A	N/A	N/A	N/A
4	Net Metering Customers	OS	-	N/A	N/A	N/A
5	Power Exchanges					
6	Bonneville Power Administration	EX	-			
7	NorthWestern Energy	EX	-			
8	PacifiCorp Inc.	EX	-			
9	Puget Sound Energy, Inc.	EX	-			
10	Sierra Pacific Power Co., dba NV Energ	EX	-			
11	Utah Associated Municipal Power System	EX	-			
12	Portland General Electric Company	EX	WSPP			
13	Other Transactions					
14	Acctg Valuation of Portland General El					
	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	04/12/2010	End of 2009/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)	
					987,160	987,160	1
75,948				4,348,699		4,348,699	2
296,606				15,150,915		15,150,915	3
508				37,631		37,631	4
							5
	58,844	12,463					6
		3,301					7
	56,147	220,977					8
	274						9
		10,947					10
	12						11
	80,112	80,112					12
					111,600	111,600	13
							14
2,911,842	195,389	327,800	2,815,124	153,627,912	4,126,029	160,569,065	

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: 326.4 Line No.: 3 Column: a

Ida West, a subsidiary of Idaho Power Company, has partial ownership of these projects.

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.: 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.: 6 Column: b

Financial Transmission Losses

Schedule Page: 326.6 Line No.: 8 Column: b

Non Firm Purchases

Schedule Page: 326.8 Line No.: 2 Column: b

ISDA Master Agreement with Morgan Stanley dated 03/01/2000

Schedule Page: 326.8 Line No.: 11 Column: b

Financial Transmission Losses

Schedule Page: 326.8 Line No.: 14 Column: b

2008 Correction

Schedule Page: 326.9 Line No.: 1 Column: b

Non Firm Purchases

Schedule Page: 326.9 Line No.: 4 Column: b

Non Firm Purchases

Schedule Page: 326.9 Line No.: 6 Column: b

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

Schedule Page: 326.9 Line No.: 8 Column: b

Inadvertent Financial Settlement

Schedule Page: 326.9 Line No.: 10 Column: b

Non Firm Purchases

Schedule Page: 326.9 Line No.: 13 Column: b

Non Firm Purchases

Schedule Page: 326.10 Line No.: 4 Column: b

Short Term Unit Contingent

Schedule Page: 326.10 Line No.: 8 Column: b

Financial Transmission Losses

Schedule Page: 326.11 Line No.: 1 Column: b

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

Schedule Page: 326.11 Line No.: 2 Column: b

Unavailable

Schedule Page: 326.11 Line No.: 4 Column: b

Schedule 84 Net Metering

Schedule Page: 326.11 Line No.: 6 Column: b

Scheduled losses not removed with loss transactions.

Schedule Page: 326.11 Line No.: 7 Column: b

Scheduled losses not removed with loss transactions.

Schedule Page: 326.11 Line No.: 8 Column: b

Scheduled losses not removed with loss transactions.

Schedule Page: 326.11 Line No.: 9 Column: b

Scheduled losses not removed with loss transactions.

Schedule Page: 326.11 Line No.: 10 Column: b

Scheduled losses not removed with loss transactions.

Schedule Page: 326.11 Line No.: 11 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) 04/12/2010	Year/Period of Report End of 2009/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	Bonneville Power Administration - OTEC	Bonneville Power Administration	Oregon Trails Electric Co-op	FNO
2	Bonneville Power Administration - OTEC	Bonneville Power Administration	Oregon Trails Electric Co-op	AD
3	Bonneville Power Administration - USBR	Bonneville Power Administration	United States Bureau of Reclamati	FNO
4	Bonneville Power Administration - USBR	Bonneville Power Administration	United States Bureau of Reclamati	AD
5	Bonneville Power Administration - Raft	Bonneville Power Administration	Raft River Electric Co-op	FNO
6	Bonneville Power Administration - Raft	Bonneville Power Administration	Raft River Electric Co-op	AD
7	Bonneville Power Administration - PF	Bonneville Power Administration	Priority Firm Customers	FNO
8	Bonneville Power Administration - PF	Bonneville Power Administration	Priority Firm Customers	AD
9	Milner Irrigation District	United States Bureau of Reclamati	Milner Irrigation District	OLF
10	Cargill	Seattle City Light	Bonneville Power Administration	OS
11	PacifiCorp	PacifiCorp West	PacifiCorp West	FNO
12	PacifiCorp	PacifiCorp West	PacifiCorp West	AD
13	United States Bureau of Indian Affairs	Bonneville Power Administration	United States Bureau of Indian Af	OS
14	PacifiCorp Power Marketing	PacifiCorp West	PacifiCorp West	OS
15	PacifiCorp Power Marketing	PacifiCorp West	PacifiCorp West	AD
16	Black Hills Power			AD
17	Black Hills Power	PacifiCorp West	Bonneville Power Administration	NF
18	Black Hills Power	Bonneville Power Administration	PacifiCorp West	NF
19	Bonneville Power Admin.			AD
20	Bonneville Power Admin.	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
21	Bonneville Power Admin.	PacifiCorp East	Sierra Pacific Power	NF
22	Bonneville Power Admin.	Bonneville Power Administration	Bonneville Power Administration	NF
23	Bonneville Power Admin.	Avista	Bonneville Power Administration	NF
24	Bonneville Power Admin.	Avista	Sierra Pacific Power	NF
25	Cargill Power Markets			AD
26	Cargill Power Markets	NorthWestern/PacifiCorp East	PacifiCorp East	NF
27	Cargill Power Markets	PacifiCorp East	NorthWestern/PacifiCorp East	NF
28	Cargill Power Markets	PacifiCorp East	NorthWestern/PacifiCorp East	NF
29	Cargill Power Markets	PacifiCorp East	NorthWestern/PacifiCorp East	SFP
30	Cargill Power Markets	PacifiCorp East	PacifiCorp East	NF
31	Cargill Power Markets	PacifiCorp East	PacifiCorp East	SFP
32	Cargill Power Markets	PacifiCorp East	PacifiCorp West	NF
33	Cargill Power Markets	PacifiCorp East	Bonneville Power Administration	NF
34	Cargill Power Markets	PacifiCorp East	Bonneville Power Administration	SFP
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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)	MegaWatt Hours Delivered (j)	Line No.
5.00000				382,722	382,722	1
5.00000						2
5.00000				193,638	193,638	3
5.00000						4
5.00000				224,865	224,865	5
5.00000						6
5.00000				803,029	803,029	7
5.00000						8
Legacy	Minidoka, Idaho	Various in Idaho		8,494	8,494	9
10.00000				321,755	321,755	10
5.00000				2,232	2,232	11
5.00000						12
Legacy	LaGrande, Oregon	Various in Idaho		12,465	12,465	13
Legacy (440)	JBSN	ENPR		3,292	3,292	14
Legacy (440)	JBSN	ENPR				15
5.00000						16
5.00000	JBSN	LGBP		406	406	17
5.00000	LGBP	JBSN		310	310	18
5.00000						19
5.00000	BPAT.NWMT	OTEC		204	204	20
5.00000	BRDY	M345		200	200	21
5.00000	LGBP	LGBP		753	753	22
5.00000	LOLO	LGBP		17,425	17,425	23
5.00000	LOLO	M345		1,783	1,783	24
5.00000						25
5.00000	AVAT.NWMT	BORA		496	496	26
5.00000	BORA	AVAT.NWMT		869	869	27
5.00000	BORA	BPAT.NWMT		351	351	28
5.00000	BORA	BPAT.NWMT		667	667	29
5.00000	BORA	BRDY		180	180	30
5.00000	BORA	BRDY		400	400	31
5.00000	BORA	ENPR		7,859	7,859	32
5.00000	BORA	LGBP		22,470	22,470	33
5.00000	BORA	LGBP		22,834	22,834	34
			0	**4,134,363**	**4,134,363**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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	PacifiCorp East	Avista	NF
2	Cargill Power Markets	PacifiCorp East	Avista	SFP
3	Cargill Power Markets	PacifiCorp East	Sierra Pacific Power	NF
4	Cargill Power Markets	PacifiCorp East	Sierra Pacific Power	SFP
5	Cargill Power Markets	NorthWestern/PacifiCorp East	PacifiCorp East	NF
6	Cargill Power Markets	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
7	Cargill Power Markets	NorthWestern/PacifiCorp East	PacifiCorp East	NF
8	Cargill Power Markets	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
9	Cargill Power Markets	NorthWestern/PacifiCorp East	Sierra Pacific Power	SFP
10	Cargill Power Markets	PacifiCorp East	PacifiCorp East	NF
11	Cargill Power Markets	PacifiCorp East	Sierra Pacific Power	SFP
12	Cargill Power Markets	PacifiCorp East	NorthWestern/PacifiCorp East	NF
13	Cargill Power Markets	PacifiCorp West	PacifiCorp East	NF
14	Cargill Power Markets	PacifiCorp West	PacifiCorp East	SFP
15	Cargill Power Markets	PacifiCorp West	Sierra Pacific Power	NF
16	Cargill Power Markets	NorthWestern/PacifiCorp East	PacifiCorp East	NF
17	Cargill Power Markets	NorthWestern/PacifiCorp East	Sierra Pacific Power	SFP
18	Cargill Power Markets	PacifiCorp West	PacifiCorp East	NF
19	Cargill Power Markets	PacifiCorp West	PacifiCorp West	NF
20	Cargill Power Markets	PacifiCorp West	Bonneville Power Administration	NF
21	Cargill Power Markets	PacifiCorp West	Bonneville Power Administration	SFP
22	Cargill Power Markets	PacifiCorp West	Sierra Pacific Power	NF
23	Cargill Power Markets	PacifCorp West	Sierra Pacific Power	SFP
24	Cargill Power Markets	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
25	Cargill Power Markets	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
26	Cargill Power Markets	Bonneville Power Administration	PacifiCorp East	NF
27	Cargill Power Markets	Bonneville Power Administration	PacifiCorp East	SFP
28	Cargill Power Markets	Bonneville Power Administration	Idaho Power Company	NF
29	Cargill Power Markets	Bonneville Power Administration	Sierra Pacific Power	NF
30	Cargill Power Markets	Bonneville Power Administration	Sierra Pacific Power	SFP
31	Cargill Power Markets	Avista	PacifiCorp East	NF
32	Cargill Power Markets	Avista	PacifiCorp East	SFP
33	Cargill Power Markets	Avista	Sierra Pacific Power	NF
34	Cargill Power Markets	Sierra Pacific Power	PacifiCorp East	NF
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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.
5.00000	BORA	LOLO		234	234	1
5.00000	BORA	LOLO		1,288	1,288	2
5.00000	BORA	M345		3,839	3,839	3
5.00000	BORA	M345		39,937	39,937	4
5.00000	BPAT.NWMT	BORA		2,139	2,139	5
5.00000	BPAT.NWMT	BORA		4,192	4,192	6
5.00000	BPAT.NWMT	BRDY		11,406	11,406	7
5.00000	BPAT.NWMT	M345		872	872	8
5.00000	BPAT.NWMT	M345		384	384	9
5.00000	BRDY	BORA				10
5.00000	BRDY	M345				11
5.00000	BRDY	BPAT.NWMT		39	39	12
5.00000	ENPR	BORA		64,175	64,175	13
5.00000	ENPR	BORA		8,300	8,300	14
5.00000	ENPR	M345		2,812	2,812	15
5.00000	HTSP	BRDY		2,861	2,861	16
5.00000	HTSP	M345		492	492	17
5.00000	JBSN	BORA		256	256	18
5.00000	JBSN	ENPR		3,396	3,396	19
5.00000	JBSN	LGBP		8,722	8,722	20
5.00000	JBSN	LGBP		5,104	5,104	21
5.00000	JBSN	M345		3,106	3,106	22
5.00000	JBSN	M345		5,561	5,561	23
5.00000	JEFF	LGBP		161	161	24
5.00000	JEFF	M345		90	90	25
5.00000	LGBP	BORA		10,087	10,087	26
5.00000	LGBP	BORA		445	445	27
5.00000	LGBP	IPCO		609	609	28
5.00000	LGBP	M345		16,682	16,682	29
5.00000	LGBP	M345		2,248	2,248	30
5.00000	LOLO	BORA		1,301	1,301	31
5.00000	LOLO	BORA		528	528	32
5.00000	LOLO	M345		993	993	33
5.00000	LYPK	BORA		23,832	23,832	34
			0	4,134,363	4,134,363	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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	Sierra Pacific Power	PacifiCorp East	SFP
2	Cargill Power Markets	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
3	Cargill Power Markets	Sierra Pacific Power	PacifiCorp East	NF
4	Cargill Power Markets	Sierra Pacific Power	PacifiCorp East	SFP
5	Cargill Power Markets	Sierra Pacific Power	NorthWestern/PacifiCorp East	SFP
6	Cargill Power Markets	Sierra Pacific Power	Bonneville Power Administration	NF
7	Cargill Power Markets	Sierra Pacific Power	Bonneville Power Administration	SFP
8	Cargill Power Markets	Sierra Pacific Power	Avista	NF
9	Cargill Power Markets	Sierra Pacific Power	Avista	SFP
10	Cargill Power Markets	Sierra Pacific Power	Sierra Pacific Power	NF
11	Cargill Power Markets	Sierra Pacific Power	Sierra Pacific Power	SFP
12	Cargill Power Markets	Sierra Pacific Power	PacifiCorp East	NF
13	Cargill Power Markets	Sierra Pacific Power	Bonneville Power Administration	NF
14	Cargill Power Markets	Sierra Pacific Power	Bonneville Power Administration	SFP
15	Cargill Power Markets	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
16	Cargill Power Markets	Idaho Power Company	Idaho Power Company	NF
17	Cargill Power Markets	PacifiCorp East	PacifiCorp East	NF
18	Cargill Power Markets	Idaho Power Company	Idaho Power Company	NF
19	Cargill Power Markets	Idaho Power Company	Bonneville Power Administration	NF
20	Cargill Power Markets	Idaho Power Company	Sierra Pacific Power	NF
21	Citigroup Energy			AD
22	Citigroup Energy			NF
23	Conoco Phillips			AD
24	Constellation Energy			AD
25	Constellation Energy			NF
26	Coral Power			AD
27	Coral Power	PacifiCorp East	Bonneville Power Administration	NF
28	Coral Power	PacifiCorp East	Avista	NF
29	Coral Power	PacifiCorp East	Sierra Pacific Power	NF
30	Coral Power	PacifiCorp East	Bonneville Power Administration	NF
31	Coral Power	PacifiCorp East	Sierra Pacific Power	NF
32	Coral Power	Idaho Power Company	Sierra Pacific Power	NF
33	Coral Power	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
34	Coral Power	Bonneville Power Administration	PacifiCorp East	NF
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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.
5.00000	LYPK	BORA		26,508	26,508	1
5.00000	LYPK	BPAT.NWMT		15	15	2
5.00000	LYPK	BRDY		10,302	10,302	3
5.00000	LYPK	BRDY		288	288	4
5.00000	LYPK	HTSP		64	64	5
5.00000	LYPK	LGBP		33,433	33,433	6
5.00000	LYPK	LGBP		288	288	7
5.00000	LYPK	LOLO		79	79	8
5.00000	LYPK	LOLO		391	391	9
5.00000	LYPK	M345		33,280	33,280	10
5.00000	LYPK	M345		186,991	186,991	11
5.00000	M345	BORA		45	45	12
5.00000	M345	LGBP		3,417	3,417	13
5.00000	M345	LGBP		40	40	14
5.00000	M345	BPAT.NWMT		25	25	15
5.00000	MDSK	IPCO		12	12	16
5.00000	MLCK	BRDY		2,663	2,663	17
5.00000	OBBLPR	IPCO		15	15	18
5.00000	OBBLPR	LGBP		50	50	19
5.00000	OBBLPR	M345		15	15	20
5.00000						21
5.00000						22
5.00000						23
5.00000						24
5.00000						25
5.00000						26
5.00000	BORA	LGBP		1,267	1,267	27
5.00000	BORA	LOLO		288	288	28
5.00000	BORA	M345		4,760	4,760	29
5.00000	BRDY	LGBP		506	506	30
5.00000	BRDY	M345		1,724	1,724	31
5.00000	JBWT	M345		450	450	32
5.00000	JEFF	LGBP		644	644	33
5.00000	LGBP	BORA		25	25	34
			0	**4,134,363**	**4,134,363**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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	Sierra Pacific Power	NF
3	Coral Power	Sierra Pacific Power	PacifiCorp East	NF
4	Coral Power	Sierra Pacific Power	Bonneville Power Administration	NF
5	Energy Authority			AD
6	Endure Energy	PacifiCorp East	Bonneville Power Administration	NF
7	Endure Energy	PacifiCorp East	Bonneville Power Administration	SFP
8	Endure Energy	PacifiCorp East	Avista	NF
9	Endure Energy	PacifiCorp East	Avista	SFP
10	Highland Energy			AD
11	Macquarie Cook	PacifiCorp East	Bonneville Power Administration	NF
12	Morgan Stanley Capital Group			AD
13	Morgan Stanley Capital Group	PacifiCorp East	Bonneville Power Administration	NF
14	Morgan Stanley Capital Group	PacifiCorp East	Avista	NF
15	Morgan Stanley Capital Group	NorthWestern/PacifiCorp East	PacifiCorp East	NF
16	Morgan Stanley Capital Group	PacifiCorp East	Bonneville Power Administration	NF
17	Morgan Stanley Capital Group	NorthWestern/PacifiCorp East	PacifiCorp East	NF
18	Morgan Stanley Capital Group	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
19	Morgan Stanley Capital Group	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
20	Morgan Stanley Capital Group	Bonneville Power Administration	PacifiCorp East	NF
21	Morgan Stanley Capital Group	PacifiCorp East	PacifiCorp East	NF
22	Northwestern Energy			AD
23	Northwestern Energy (Merchant)	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
24	Pacificorp Power Marketing			AD
25	Pacificorp Power Marketing	PacifiCorp East	PacifiCorp West	NF
26	Pacificorp Power Marketing	PacifiCorp East	PacifiCorp West	NF
27	Pacificorp Power Marketing	PacifiCorp East	Idaho Power Company	NF
28	Pacificorp Power Marketing	PacifiCorp East	PacifiCorp East	SFP
29	Pacificorp Power Marketing	PacifiCorp East	Bonneville Power Administration	NF
30	Pacificorp Power Marketing	PacifiCorp East	Sierra Pacific Power	NF
31	Pacificorp Power Marketing	PacifiCorp East	Sierra Pacific Power	SFP
32	Pacificorp Power Marketing	PacifiCorp East	PacifiCorp West	NF
33	Pacificorp Power Marketing	PacifiCorp East	PacifiCorp East	NF
34	Pacificorp Power Marketing	PacifiCorp East	PacifiCorp West	NF
	TOTAL			

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
5.00000	LGBP	M345		4,931	4,931	1
5.00000	LOLO	M345		308	308	2
5.00000	M345	BRDY		150	150	3
5.00000	M345	LGBP		870	870	4
5.00000						5
5.00000	BORA	LGBP		1,106	1,106	6
5.00000	BORA	LGBP		4,938	4,938	7
5.00000	BORA	LOLO		2,075	2,075	8
5.00000	BORA	LOLO		600	600	9
5.00000						10
5.00000	BORA	LGBP		11	11	11
5.00000						12
5.00000	BORA	LGBP		12,902	12,902	13
5.00000	BORA	LOLO		1,257	1,257	14
5.00000	BPAT.NWMT	BRDY		35	35	15
5.00000	BRDY	LGBP		184	184	16
5.00000	HTSP	BRDY		38	38	17
5.00000	JEFF	LGBP		339	339	18
5.00000	JEFF	M345		285	285	19
5.00000	LGBP	BRDY		54	54	20
5.00000	MLCK	BRDY		997	997	21
5.00000						22
5.00000	JEFF	LGBP		46	46	23
5.00000						24
5.00000	BORA	ENPR		182,128	182,128	25
5.00000	BORA	JBSN		160	160	26
5.00000	BORA	JBWT		464	464	27
5.00000	BORA	KPRT		48	48	28
5.00000	BORA	LGBP		3,993	3,993	29
5.00000	BORA	M345		3,689	3,689	30
5.00000	BORA	M345		3,393	3,393	31
5.00000	BORA	M500		950	950	32
5.00000	BRDY	BRDY		2,183	2,183	33
5.00000	BRDY	ENPR		1,399	1,399	34
			0	**4,134,363**	**4,134,363**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/Q4

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

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

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

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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 (Substation 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.
5.00000	BRDY	LGBP		2,465	2,465	1
5.00000	ENPR	BORA		24,022	24,022	2
5.00000	ENPR	BRDY		4,300	4,300	3
5.00000	ENPR	LGBP		63	63	4
5.00000	ENPR	LOLO		50	50	5
5.00000	ENPR	M345		1,453	1,453	6
5.00000	JBWT	BORA		14,163	14,163	7
5.00000	JBWT	BORA		57,723	57,723	8
5.00000	JBWT	BRDY		144,577	144,577	9
5.00000	JBWT	BRDY		221	221	10
5.00000	JBWT	ENPR		1,375	1,375	11
5.00000	JBWT	M345		2,673	2,673	12
5.00000	JBWT	M500		-11,278	-11,278	13
5.00000	JBWT	M500		542,728	542,728	14
5.00000	LGBP	BORA		969	969	15
5.00000	LGBP	M345		275	275	16
5.00000	LOLO	ENPR		3,039	3,039	17
5.00000						18
5.00000	BPAT.NWMT	LGBP		160	160	19
5.00000	BRDY	LGBP		63	63	20
5.00000	JEFF	LGBP		7,348	7,348	21
5.00000	M345	LGBP		450	450	22
5.00000	MLCK	BRDY		2,348	2,348	23
5.00000						24
5.00000	BORA	BPAT.NWMT		798	798	25
5.00000	BORA	BRDY		801	801	26
5.00000	BORA	ENPR		2,692	2,692	27
5.00000	BORA	LGBP		83,840	83,840	28
5.00000	BORA	LGBP		3,584	3,584	29
5.00000	BORA	LOLO		2,251	2,251	30
5.00000	BORA	M345		85	85	31
5.00000	BPAT.NWMT	BORA				32
5.00000	BPAT.NWMT	BRDY		544	544	33
5.00000	BPAT.NWMT	BRDY		6,466	6,466	34
			0	**4,134,363**	**4,134,363**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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.	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
2	Powerex Corp.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
3	Powerex Corp.	PacifiCorp East	NorthWestern/PacifiCorp East	NF
4	Powerex Corp.	PacifiCorp East	PacifiCorp West	NF
5	Powerex Corp.	PacifiCorp East	Idaho Power Company	NF
6	Powerex Corp.	PacifiCorp East	Bonneville Power Administration	NF
7	Powerex Corp.	PacifiCorp East	Bonneville Power Administration	SFP
8	Powerex Corp.	PacifiCorp East	Avista	NF
9	Powerex Corp.	PacifiCorp East	Sierra Pacific Power	NF
10	Powerex Corp.	PacifiCorp East	Sierra Pacific Power	SFP
11	Powerex Corp.	PacifiCorp West	PacifiCorp East	NF
12	Powerex Corp.	PacifiCorp West	PacifiCorp East	NF
13	Powerex Corp.	PacifiCorp West	PacifiCorp East	SFP
14	Powerex Corp.	PacifiCorp West	PacifiCorp West	NF
15	Powerex Corp.	PacifiCorp West	Sierra Pacific Power	NF
16	Powerex Corp.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
17	Powerex Corp.	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
18	Powerex Corp.	NorthWestern/PacifiCorp East	Sierra Pacific Power	SFP
19	Powerex Corp.	PacifiCorp West	NorthWestern/PacifiCorp East	NF
20	Powerex Corp.	PacifiCorp West	NorthWestern/PacifiCorp East	NF
21	Powerex Corp.	PacifiCorp West	PacifiCorp East	NF
22	Powerex Corp.	PacifiCorp West	PacifiCorp West	NF
23	Powerex Corp.	PacifiCorp West	Idaho Power Company	NF
24	Powerex Corp.	PacifiCorp West	NorthWestern/PacifiCorp East	NF
25	Powerex Corp.	PacifiCorp West	Bonneville Power Administration	NF
26	Powerex Corp.	PacifiCorp West	Avista	NF
27	Powerex Corp.	PacifiCorp West	Sierra Pacific Power	NF
28	Powerex Corp.	PacifiCorp West	PacifiCorp West	NF
29	Powerex Corp.	Idaho Power Company	NorthWestern/PacifiCorp East	NF
30	Powerex Corp.	Idaho Power Company	PacifiCorp West	NF
31	Powerex Corp.	Idaho Power Company	Bonneville Power Administration	NF
32	Powerex Corp.	Idaho Power Company	Avista	NF
33	Powerex Corp.	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
34	Powerex Corp.	Bonneville Power Administration	PacifiCorp East	NF
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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.
5.00000	BPAT.NWMT	LGBP		563	563	1
5.00000	BPAT.NWMT	M345		100	100	2
5.00000	BRDY	BPAT.NWMT		87	87	3
5.00000	BRDY	ENPR		2,872	2,872	4
5.00000	BRDY	IPCO		200	200	5
5.00000	BRDY	LGBP		16,760	16,760	6
5.00000	BRDY	LGBP		8,876	8,876	7
5.00000	BRDY	LOLO		4	4	8
5.00000	BRDY	M345		13	13	9
5.00000	BRDY	M345		16,135	16,135	10
5.00000	ENPR	BORA		2,342	2,342	11
5.00000	ENPR	BRDY		72,729	72,729	12
5.00000	ENPR	BRDY		49,763	49,763	13
5.00000	ENPR	JBSN		37	37	14
5.00000	ENPR	M345		6,911	6,911	15
5.00000	HTSP	BRDY		1,254	1,254	16
5.00000	HTSP	BRDY		12,889	12,889	17
5.00000	HTSP	M345		6,708	6,708	18
5.00000	JBSN	AVAT.NWMT		10	10	19
5.00000	JBSN	BPAT.NWMT		248	248	20
5.00000	JBSN	BRDY		543	543	21
5.00000	JBSN	ENPR		340	340	22
5.00000	JBSN	IPCO		800	800	23
5.00000	JBSN	JEFF		64	64	24
5.00000	JBSN	LGBP		12,794	12,794	25
5.00000	JBSN	LOLO		38	38	26
5.00000	JBSN	M345		18	18	27
5.00000	JBSN	M500		17	17	28
5.00000	JBWT	BPAT.NWMT		86	86	29
5.00000	JBWT	ENPR		313	313	30
5.00000	JBWT	LGBP		6,940	6,940	31
5.00000	JBWT	LOLO		72	72	32
5.00000	JEFF	LGBP		479	479	33
5.00000	LGBP	BORA		5,675	5,675	34
			0	**4,134,363**	**4,134,363**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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.	Bonneville Power Administration	PacifiCorp East	NF
2	Powerex Corp.	Bonneville Power Administration	PacifiCorp West	NF
3	Powerex Corp.	Bonneville Power Administration	Sierra Pacific Power	NF
4	Powerex Corp.	Bonneville Power Administration	Sierra Pacific Power	NF
5	Powerex Corp.	Avista	PacifiCorp East	NF
6	Powerex Corp.	Avista	PacifiCorp East	NF
7	Powerex Corp.	Avista	Sierra Pacific Power	NF
8	Powerex Corp.	Sierra Pacific Power	PacifiCorp East	NF
9	Powerex Corp.	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
10	Powerex Corp.	Sierra Pacific Power	PacifiCorp East	NF
11	Powerex Corp.	Sierra Pacific Power	Bonneville Power Administration	NF
12	Powerex Corp.	Sierra Pacific Power	Avista	NF
13	Powerex Corp.	PacifiCorp East	PacifiCorp East	NF
14	PPL EnergyPlus, LLC (EPLU)			AD
15	PPL EnergyPlus, LLC (EPLU)	PacifiCorp East	Bonneville Power Administration	NF
16	PPL EnergyPlus, LLC (EPLU)	PacifiCorp East	Bonneville Power Administration	SFP
17	PPL EnergyPlus, LLC (EPLU)	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
18	PPL EnergyPlus, LLC (EPLU)	PacifiCorp East	PacifiCorp East	NF
19	PPM Energy			AD
20	PPM Energy	PacifiCorp East	Bonneville Power Administration	NF
21	PPM Energy	PacifiCorp East	Avista	NF
22	PPM Energy	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
23	PPM Energy	Bonneville Power Administration	PacifiCorp East	NF
24	PPM Energy	Bonneville Power Administration	Idaho Power Company	NF
25	PPM Energy	Sierra Pacific Power	Bonneville Power Administration	NF
26	PPM Energy	PacifiCorp East	PacifiCorp East	NF
27	Puget Sound Energy			AD
28	Puget Sound Energy	PacifiCorp East	Bonneville Power Administration	NF
29	Puget Sound Energy	PacifiCorp East	PacifiCorp East	NF
30	Rainbow Energy Marketing Company			AD
31	Rainbow Energy Marketing Company	PacifiCorp East	PacifiCorp East	NF
32	Rainbow Energy Marketing Company	PacifiCorp East	Bonneville Power Administration	NF
33	Rainbow Energy Marketing Company	PacifiCorp East	Avista	NF
34	Rainbow Energy Marketing Company	PacifiCorp East	Sierra Pacific Power	NF
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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.
5.00000	LGBP	BRDY		564	564	1
5.00000	LGBP	JBSN		519	519	2
5.00000	LGBP	M345		985	985	3
5.00000	LGBP	M345		4,420	4,420	4
5.00000	LOLO	BORA		430	430	5
5.00000	LOLO	BRDY		228	228	6
5.00000	LOLO	M345		557	557	7
5.00000	M345	BORA		39	39	8
5.00000	M345	BPAT.NWMT		19	19	9
5.00000	M345	BRDY		1,293	1,293	10
5.00000	M345	LGBP		6,242	6,242	11
5.00000	M345	LOLO		114	114	12
5.00000	MLCK	BRDY		4,780	4,780	13
5.00000						14
5.00000	BRDY	LGBP		3,930	3,930	15
5.00000	BRDY	LGBP		13,958	13,958	16
5.00000	JEFF	LGBP		4,276	4,276	17
5.00000	MLCK	BRDY		3,255	3,255	18
5.00000						19
5.00000	BORA	LGBP		3,564	3,564	20
5.00000	BORA	LOLO		400	400	21
5.00000	JEFF	LGBP		1,800	1,800	22
5.00000	LGBP	BORA		686	686	23
5.00000	LGBP	IPCO		100	100	24
5.00000	M345	LGBP		300	300	25
5.00000	MLCK	BRDY		1,220	1,220	26
5.00000						27
5.00000	BRDY	LGBP		7,588	7,588	28
5.00000	MLCK	BRDY		1,320	1,320	29
5.00000						30
5.00000	BORA	BRDY		400	400	31
5.00000	BORA	LGBP		590	590	32
5.00000	BORA	LOLO		3,780	3,780	33
5.00000	BORA	M345		6,529	6,529	34
			0	**4,134,363**	**4,134,363**	

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	04/12/2010	End of 2009/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	PacifiCorp East	Sierra Pacific Power	SFP
2	Rainbow Energy Marketing Company	NorthWestern/PacifiCorp East	PacifiCorp East	NF
3	Rainbow Energy Marketing Company	NorthWestern/PacifiCorp East	PacifiCorp East	NF
4	Rainbow Energy Marketing Company	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
5	Rainbow Energy Marketing Company	NorthWestern/PacifiCorp East	Sierra Pacific Power	SFP
6	Rainbow Energy Marketing Company	PacifiCorp East	Bonneville Power Administration	NF
7	Rainbow Energy Marketing Company	PacifiCorp East	Avista	NF
8	Rainbow Energy Marketing Company	PacifiCorp East	Avista	SFP
9	Rainbow Energy Marketing Company	PacifiCorp East	Sierra Pacific Power	NF
10	Rainbow Energy Marketing Company	PacifiCorp East	Sierra Pacific Power	SFP
11	Rainbow Energy Marketing Company	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
12	Rainbow Energy Marketing Company	NorthWestern/PacifiCorp East	Avista	NF
13	Rainbow Energy Marketing Company	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
14	Rainbow Energy Marketing Company	Bonneville Power Administration	Sierra Pacific Power	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	Seattle City Light			AD
20	Seattle City Light			NF
21	Sempra Energy			AD
22	Sierra Pacific Power			AD
23	Sierra Pacific Power	PacifiCorp East	Avista	NF
24	Sierra Pacific Power	PacifiCorp East	Sierra Pacific Power	NF
25	Sierra Pacific Power	PacifiCorp East	Sierra Pacific Power	SFP
26	Sierra Pacific Power	NorthWestern/PacifiCorp East	PacifiCorp East	NF
27	Sierra Pacific Power	PacifiCorp East	Sierra Pacific Power	NF
28	Sierra Pacific Power	PacifiCorp East	Sierra Pacific Power	SFP
29	Sierra Pacific Power	NorthWestern/PacifiCorp East	PacifiCorp East	NF
30	Sierra Pacific Power	PacifiCorp West	Sierra Pacific Power	NF
31	Sierra Pacific Power	NorthWestern/PacifiCorp East	PacifiCorp East	NF
32	Sierra Pacific Power	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
33	Sierra Pacific Power	Bonneville Power Administration	Sierra Pacific Power	NF
34	Sierra Pacific Power	Avista	Sierra Pacific Power	NF
	TOTAL			

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Substation 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.
5.00000	BORA	M345		1,296	1,296	1
5.00000	BPAT.NWMT	BORA		240	240	2
5.00000	BPAT.NWMT	BRDY		533	533	3
5.00000	BPAT.NWMT	M345		733	733	4
5.00000	BPAT.NWMT	M345		275	275	5
5.00000	BRDY	LGBP		1,020	1,020	6
5.00000	BRDY	LOLO		400	400	7
5.00000	BRDY	LOLO		1,051	1,051	8
5.00000	BRDY	M345		1,024	1,024	9
5.00000	BRDY	M345		456	456	10
5.00000	JEFF	LGBP		1,000	1,000	11
5.00000	JEFF	LOLO		1,200	1,200	12
5.00000	JEFF	M345		175	175	13
5.00000	LGBP	M345		345	345	14
5.00000	LOLO	M345		1,853	1,853	15
5.00000	LOLO	M345		1,312	1,312	16
5.00000	M345	LGBP		45	45	17
5.00000	MLCK	BRDY		4,451	4,451	18
5.00000						19
5.00000						20
5.00000						21
5.00000						22
5.00000	BORA	LOLO		2	2	23
5.00000	BORA	M345		2,624	2,624	24
5.00000	BORA	M345		5,353	5,353	25
5.00000	BPAT.NWMT	BRDY		1,105	1,105	26
5.00000	BRDY	M345		867	867	27
5.00000	BRDY	M345		400	400	28
5.00000	HTSP	BRDY		6,826	6,826	29
5.00000	JBSN	M345		3,982	3,982	30
5.00000	JEFF	BORA		90	90	31
5.00000	JEFF	M345		10,826	10,826	32
5.00000	LGBP	M345		53,969	53,969	33
5.00000	LOLO	M345		7,628	7,628	34
			0	**4,134,363**	**4,134,363**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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	Sierra Pacific Power	PacifiCorp East	NF
2	Sierra Pacific Power	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
3	Sierra Pacific Power	Sierra Pacific Power	PacifiCorp East	NF
4	Sierra Pacific Power	Sierra Pacific Power	PacifiCorp West	NF
5	Sierra Pacific Power	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
6	Sierra Pacific Power	Sierra Pacific Power	Bonneville Power Administration	NF
7	Sierra Pacific Power	Sierra Pacific Power	Avista	NF
8	Sierra Pacific Power	PacifiCorp East	PacifiCorp East	NF
9	Sierra Pacific Power	Idaho Power Company	Idaho Power Company	NF
10	TransAlta Energy Marketing			AD
11	TransAlta Energy Marketing	PacifiCorp East	Bonneville Power Administration	NF
12	TransAlta Energy Marketing	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
13	TransAlta Energy Marketing	PacifiCorp East	Bonneville Power Administration	NF
14	TransAlta Energy Marketing	NorthWestern/PacifiCorp East	PacifiCorp East	NF
15	TransAlta Energy Marketing	Bonneville Power Administration	PacifiCorp East	NF
16	TransAlta Energy Marketing	Bonneville Power Administration	PacifiCorp East	NF
17	TransAlta Energy Marketing	Bonneville Power Administration	Sierra Pacific Power	NF
18	TransAlta Energy Marketing	Sierra Pacific Power	Bonneville Power Administration	NF
19	UAMPS			AD
20	UAMPS	PacifiCorp East	Sierra Pacific Power	NF
21	WPSE Integrys Energy			AD
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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.
5.00000	M345	BORA		325	325	1
5.00000	M345	BPAT.NWMT		75	75	2
5.00000	M345	BRDY		15	15	3
5.00000	M345	JBSN		886	886	4
5.00000	M345	JEFF		115	115	5
5.00000	M345	LGBP		15,478	15,478	6
5.00000	M345	LOLO		818	818	7
5.00000	MLCK	BRDY		3,443	3,443	8
5.00000	OBBLPR	IPCO		272	272	9
5.00000						10
5.00000	BORA	LGBP		6,367	6,367	11
5.00000	BPAT.NWMT	M345		80	80	12
5.00000	BRDY	LGBP		111	111	13
5.00000	HTSP	BRDY		175	175	14
5.00000	LGBP	BORA		125	125	15
5.00000	LGBP	BRDY		21	21	16
5.00000	LGBP	M345		561	561	17
5.00000	M345	LGBP		348	348	18
5.00000						19
5.00000	BORA	M345		345	345	20
5.00000						21
0.00000						22
0.00000						23
0.00000						24
0.00000						25
0.00000						26
0.00000						27
0.00000						28
0.00000						29
0.00000						30
0.00000						31
0.00000						32
0.00000						33
0.00000						34
			0	4,134,363	4,134,363	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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.
1,068,534	377,593		1,446,127	1
-900,632			-900,632	2
1,051,680	145,585		1,197,265	3
-427,971			-427,971	4
462,447	-138,046		324,401	5
-457,526			-457,526	6
1,937,346	13,569		1,950,915	7
-1,815,612			-1,815,612	8
	13,760		13,760	9
	120,794		120,794	10
10,615	1,515		12,130	11
-5,077			-5,077	12
54,604			54,604	13
	11,591		11,591	14
	-5,256		-5,256	15
	-3,645		-3,645	16
	1,215		1,215	17
	928		928	18
	-44,897		-44,897	19
	488		488	20
	478		478	21
	1,800		1,800	22
	41,646		41,646	23
	4,261		4,261	24
	-1,684,723		-1,684,723	25
	271		271	26
	475		475	27
	192		192	28
	365		365	29
	98		98	30
	219		219	31
	4,300		4,300	32
	12,295		12,295	33
	12,494		12,494	34
978,408	**72,465**	**0**	**1,050,873**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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.
	128		128	1
	705		705	2
	2,101		2,101	3
	21,852		21,852	4
	1,170		1,170	5
	2,294		2,294	6
	6,241		6,241	7
	477		477	8
	210		210	9
				10
				11
	21		21	12
	35,114		35,114	13
	4,541		4,541	14
	1,539		1,539	15
	1,565		1,565	16
	269		269	17
	140		140	18
	1,858		1,858	19
	4,772		4,772	20
	2,793		2,793	21
	1,699		1,699	22
	3,043		3,043	23
	88		88	24
	49		49	25
	5,519		5,519	26
	243		243	27
	333		333	28
	9,128		9,128	29
	1,230		1,230	30
	712		712	31
	289		289	32
	543		543	33
	13,040		13,040	34
978,408	**72,465**	**0**	**1,050,873**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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.
	14,504		14,504	1
	8		8	2
	5,637		5,637	3
	158		158	4
	35		35	5
	18,293		18,293	6
	158		158	7
	43		43	8
	214		214	9
	18,209		18,209	10
	102,313		102,313	11
	25		25	12
	1,870		1,870	13
	22		22	14
	14		14	15
	7		7	16
	1,457		1,457	17
	8		8	18
	27		27	19
	8		8	20
	-572		-572	21
	3		3	22
	-330		-330	23
	-63,746		-63,746	24
	319		319	25
	-99,092		-99,092	26
	6,042		6,042	27
	1,373		1,373	28
	22,701		22,701	29
	2,413		2,413	30
	8,222		8,222	31
	2,146		2,146	32
	3,071		3,071	33
	119		119	34
978,408	**72,465**	**0**	**1,050,873**	

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	04/12/2010	End of 2009/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.
	23,516		23,516	1
	1,469		1,469	2
	715		715	3
	4,149		4,149	4
	-4		-4	5
	2,403		2,403	6
	10,730		10,730	7
	5,167		5,167	8
	646		646	9
	-174		-174	10
	646		646	11
	-314,673		-314,673	12
	27,747		27,747	13
	2,703		2,703	14
	75		75	15
	396		396	16
	82		82	17
	729		729	18
	613		613	19
	116		116	20
	2,144		2,144	21
	-275		-275	22
	74		74	23
	-1,538,539		-1,538,539	24
	814,222		814,222	25
	715		715	26
	2,074		2,074	27
	215		215	28
	17,851		17,851	29
	16,492		16,492	30
	15,169		15,169	31
	4,247		4,247	32
	9,759		9,759	33
	6,254		6,254	34
978,408	**72,465**	**0**	**1,050,873**	

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	04/12/2010	End of 2009/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.
	11,020		11,020	1
	107,393		107,393	2
	19,224		19,224	3
	282		282	4
	224		224	5
	6,496		6,496	6
	63,317		63,317	7
	258,057		258,057	8
	646,346		646,346	9
	988		988	10
	6,147		6,147	11
	11,950		11,950	12
	-50,419		-50,419	13
	2,426,321		2,426,321	14
	4,332		4,332	15
	1,229		1,229	16
	13,586		13,586	17
	-26,303		-26,303	18
	283		283	19
	112		112	20
	13,005		13,005	21
	796		796	22
	4,156		4,156	23
	-2,112,297		-2,112,297	24
	2,971		2,971	25
	2,982		2,982	26
	10,022		10,022	27
	312,137		312,137	28
	13,343		13,343	29
	8,381		8,381	30
	316		316	31
				32
	2,025		2,025	33
	24,073		24,073	34
978,408	72,465	0	1,050,873	

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.
	2,096		2,096	1
	372		372	2
	324		324	3
	10,692		10,692	4
	745		745	5
	62,398		62,398	6
	33,045		33,045	7
	15		15	8
	48		48	9
	60,071		60,071	10
	8,719		8,719	11
	270,771		270,771	12
	185,268		185,268	13
	138		138	14
	25,730		25,730	15
	4,669		4,669	16
	47,986		47,986	17
	24,974		24,974	18
	37		37	19
	923		923	20
	2,022		2,022	21
	1,266		1,266	22
	2,978		2,978	23
	238		238	24
	47,632		47,632	25
	141		141	26
	67		67	27
	63		63	28
	320		320	29
	1,165		1,165	30
	25,838		25,838	31
	268		268	32
	1,783		1,783	33
	21,128		21,128	34
978,408	**72,465**	**0**	**1,050,873**	

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.
	2,100		2,100	1
	1,932		1,932	2
	3,667		3,667	3
	16,456		16,456	4
	1,601		1,601	5
	849		849	6
	2,074		2,074	7
	145		145	8
	71		71	9
	4,814		4,814	10
	23,239		23,239	11
	424		424	12
	17,796		17,796	13
	-41,560		-41,560	14
	6,810		6,810	15
	24,186		24,186	16
	7,409		7,409	17
	5,640		5,640	18
	-24,164		-24,164	19
	8,420		8,420	20
	945		945	21
	4,252		4,252	22
	1,621		1,621	23
	236		236	24
	709		709	25
	2,882		2,882	26
	-45,239		-45,239	27
	16,775		16,775	28
	2,918		2,918	29
	-198,037		-198,037	30
	752		752	31
	1,109		1,109	32
	7,108		7,108	33
	12,277		12,277	34
978,408	**72,465**	**0**	**1,050,873**	

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.
	2,437		2,437	1
	451		451	2
	1,002		1,002	3
	1,378		1,378	4
	517		517	5
	1,918		1,918	6
	752		752	7
	1,976		1,976	8
	1,925		1,925	9
	857		857	10
	1,880		1,880	11
	2,256		2,256	12
	329		329	13
	649		649	14
	3,484		3,484	15
	2,467		2,467	16
	85		85	17
	8,369		8,369	18
	-530,280		-530,280	19
	1,445,795		1,445,795	20
	-307,246		-307,246	21
	-1,537,074		-1,537,074	22
	5		5	23
	6,328		6,328	24
	12,908		12,908	25
	2,665		2,665	26
	2,091		2,091	27
	965		965	28
	16,460		16,460	29
	9,602		9,602	30
	217		217	31
	26,106		26,106	32
	130,142		130,142	33
	18,394		18,394	34
978,408	**72,465**	**0**	**1,050,873**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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.
	784		784	1
	181		181	2
	36		36	3
	2,137		2,137	4
	277		277	5
	37,322		37,322	6
	1,973		1,973	7
	8,303		8,303	8
	656		656	9
	-308		-308	10
	19,513		19,513	11
	245		245	12
	340		340	13
	536		536	14
	383		383	15
	64		64	16
	1,719		1,719	17
	1,067		1,067	18
	-6,266		-6,266	19
	1,085		1,085	20
	-237		-237	21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
978,408	72,465	0	1,050,873	

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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. 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.: 2 Column: h

Tariff rate refund per FERC Docket ER06-787 Final Order

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

Tariff rate refund per FERC Docket ER06-787 Final Order

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

Tariff rate refund per FERC Docket ER06-787 Final Order

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

Tariff rate refund per FERC Docket ER06-787 Final Order

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. City of Seattle has sold this transmission service request to Cargill and Cargill is now responsible for payment.

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

The contract between Idaho Power and PacifiCorp - Imnaha expires on September 30, 2010.

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

Tariff rate refund per FERC Docket ER06-787 Final Order

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

Legacy, contract prior to the Open Access Transmission Tariff

Schedule Page: 328 Line No.: 13 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.: 14 Column: e

Legacy, contract prior to the Open Access Transmission Tariff

Schedule Page: 328 Line No.: 14 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.: 15 Column: e

Legacy, contract prior to the Open Access Transmission Tariff

Schedule Page: 328 Line No.: 15 Column: h
Tariff rate refund per FERC Docket ER06-787 Final Order

Schedule Page: 328 Line No.: 16 Column: h
Tariff rate refund per FERC Docket ER06-787 Final Order

Schedule Page: 328 Line No.: 19 Column: h
Tariff rate refund per FERC Docket ER06-787 Final Order

Schedule Page: 328 Line No.: 25 Column: h
Tariff rate refund per FERC Docket ER06-787 Final Order

Schedule Page: 328.2 Line No.: 21 Column: h
Tariff rate refund per FERC Docket ER06-787 Final Order

Schedule Page: 328.2 Line No.: 23 Column: h
Tariff rate refund per FERC Docket ER06-787 Final Order

Schedule Page: 328.2 Line No.: 24 Column: h
Tariff rate refund per FERC Docket ER06-787 Final Order

Schedule Page: 328.2 Line No.: 26 Column: h
Tariff rate refund per FERC Docket ER06-787 Final Order

Schedule Page: 328.3 Line No.: 5 Column: h
Tariff rate refund per FERC Docket ER06-787 Final Order

Schedule Page: 328.3 Line No.: 10 Column: h
Tariff rate refund per FERC Docket ER06-787 Final Order

Schedule Page: 328.3 Line No.: 12 Column: h
Tariff rate refund per FERC Docket ER06-787 Final Order

Schedule Page: 328.3 Line No.: 22 Column: h
Tariff rate refund per FERC Docket ER06-787 Final Order

Schedule Page: 328.3 Line No.: 24 Column: h
Tariff rate refund per FERC Docket ER06-787 Final Order

Schedule Page: 328.4 Line No.: 18 Column: h
Tariff rate refund per FERC Docket ER06-787 Final Order

Schedule Page: 328.4 Line No.: 24 Column: h
Tariff rate refund per FERC Docket ER06-787 Final Order

Schedule Page: 328.6 Line No.: 19 Column: h
Tariff rate refund per FERC Docket ER06-787 Final Order

Schedule Page: 328.6 Line No.: 27 Column: h
Tariff rate refund per FERC Docket ER06-787 Final Order

Schedule Page: 328.6 Line No.: 30 Column: h
Tariff rate refund per FERC Docket ER06-787 Final Order

Schedule Page: 328.7 Line No.: 19 Column: h
Tariff rate refund per FERC Docket ER06-787 Final Order

Schedule Page: 328.7 Line No.: 21 Column: h
Tariff rate refund per FERC Docket ER06-787 Final Order

Schedule Page: 328.7 Line No.: 22 Column: h
Tariff rate refund per FERC Docket ER06-787 Final Order

Schedule Page: 328.8 Line No.: 10 Column: h
Tariff rate refund per FERC Docket ER06-787 Final Order

Schedule Page: 328.8 Line No.: 19 Column: h
Tariff rate refund per FERC Docket ER06-787 Final Order

Schedule Page: 328.8 Line No.: 21 Column: h
Tariff rate refund per FERC Docket ER06-787 Final Order

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	04/12/2010	End of 2009/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	AD				-51,700		-51,700
2	Avista Corp	NF	88,209	88,209		375,448		375,448
3	Avista Corp	OS					-22,376	-22,376
4	Avista Corp	SFP	303,095	303,095		1,290,345		1,290,345
5	Bonneville Power Admin	LFP	409,886	409,886	1,195,428			1,195,428
6	Bonneville Power Admin	LFP			53,856			53,856
7	Bonneville Power Admin	NF	5,703	5,703		25,373		25,373
8	Bonneville Power Admin	SFP	85,496	85,496		172,706		172,706
9	Northwestern Energy	LFP	36,171	36,171	49,933	27,937		77,870
10	NorthWesern Energy	LFP	115	115	149,700			149,700
11	NorthWestern Energy	NF	4,707	4,707		25,486		25,486
12	NorthWesern Energy	OS					-137,354	-137,354
13	NorthWestern Energy	SFP	72,250	72,250		777,327		777,327
14	PacifiCorp Inc.	LFP				151,875		151,875
15	PacifiCorp Inc.	LFP	125	125		607,500		607,500
16	PacifiCorp Inc.	NF	46,893	46,893		156,935		156,935
	TOTAL		1,265,401	1,265,401	1,448,917	5,462,429	-282,651	6,628,695

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	PacifiCorp Inc.	OS					-66,394	-66,394
2	PacifiCorp Inc.	OS					516	516
3	PacifiCorp Inc.	OS					-664	-664
4	PacifiCorp Inc.	SFP	8,150	8,150		1,012,646		1,012,646
5	PaTu Wind Farm, Llc	SFP	12,967	12,967		85,881		85,881
6	Portland General Ele Co	SFP	90,177	90,177		487,013		487,013
7	Powerex Corp.	OS					-62,743	-62,743
8	Seattle City Light	SFP	78,223	78,223		198,069		198,069
9	Sierra Pacific Power Co	NF	12,939	12,939		103,490		103,490
10	Sierra Pacific Power Co	OS					10,267	10,267
11	Sierra Pacific Power Co	OS					-3,903	-3,903
12	Snohomish County PUD	SFP	10,295	10,295		16,098		16,098
13								
14								
15								
16								
	TOTAL		1,265,401	1,265,401	1,448,917	5,462,429	-282,651	6,628,695

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Schedule Page: 332 Line No.: 3 Column: g
Resale Transmission

Schedule Page: 332 Line No.: 5 Column: b
Contract Expires 09/30/2016

Schedule Page: 332 Line No.: 6 Column: b
Contract Expires 07/16/2011

Schedule Page: 332 Line No.: 9 Column: b
Contract can be terminated at anytime, with 30 days prior notice.

Schedule Page: 332 Line No.: 10 Column: b
Contract Expires 03/31/2014

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

Schedule Page: 332 Line No.: 14 Column: b
Contract Expires 06/01/2009

Schedule Page: 332 Line No.: 15 Column: b
Contract Expires 05/31/2014

Schedule Page: 332.1 Line No.: 1 Column: g
Resale Transmission

Schedule Page: 332.1 Line No.: 2 Column: g
Study Expense

Schedule Page: 332.1 Line No.: 3 Column: g
Unreserved Use Refund - Sharing Re-distributed 2008

Schedule Page: 332.1 Line No.: 7 Column: g
Resale Transmission

Schedule Page: 332.1 Line No.: 10 Column: g
Study Expense

Schedule Page: 332.1 Line No.: 11 Column: g
FERC Rate Refund

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	356,915
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	277,399
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	1,033,302
6	Richard Dahl	66,279
7	Christine King	62,095
8	Jon Miller	101,325
9	Gary Michael	63,835
10	Richard Reiten	46,624
11	Joan Smith	62,640
12	Jan Packwood	43,612
13	Judith Johansen	62,638
14	Peter O'Neill	27,200
15	Thomas Wilford	52,800
16	Robert Tintsman	64,800
17	Stephen Allred	37,283
18		
19	Chambers of Commerce & Other Civic Organizations	94,186
20		
21	Associated Taxpayers of Idaho	21,252
22	Corporate Executive Board	72,869
23	Eastern Oregon Visitor Association	1,500
24	Idaho Association of Counties	1,650
25	Idaho Association of Commerce & Industry	10,000
26	Idaho Economic Development Association	1,500
27	Misc Memberships	33,248
28	National Assoc of Corp	6,050
29	Northwest Power Pool	73,623
30	Pacific NW Utilities	35,810
31	Western Electricity Coordinating Council	827,380
32	Wyoming Taxpayers Assoc	1,500
33		
34	Misc General Management:	
35	New York Stock Exchange	7,154
36	PR Newswire	14,691
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	3,561,160

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

Recipient	Purpose	Amount
Other Purchased Services	Misc	$ 14,314
Bank of New York	Port of Morrow-PC	6,360
Deutsche Bank Amort	Broker Fees	35,000
E Source Inc	Membership	21,280
Global Insight	Data Subscription	25,934
J P Morgan Securities	Amer Falls-Port Morrow	20,592
Jet Clearing	Travel Expense	26,040
Moody's Analytics	Analyst Service	26,500
Port of Morrow	Bond Expense	5,475
Thomson/Fincancial	Analyst Service	88,354
Union Bank, N.A.	PC Bond Expense	11,360
Wells Fargo	Transfer & Fees	126,717
Stock Based Compensation	Stock Expense	511,379
Misc entries/other services	Misc	113,997
Total		$1,033,302

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	04/12/2010	End of 2009/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			7,061,068		7,061,068
2	Steam Production Plant	18,050,233				18,050,233
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	15,129,051				15,129,051
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	4,976,615				4,976,615
7	Transmission Plant	15,547,600				15,547,600
8	Distribution Plant	37,232,823				37,232,823
9	Regional Transmission and Market Operation					
10	General Plant	12,947,424				12,947,424
11	Common Plant-Electric	-296,299				-296,299
12	TOTAL	103,587,447		7,061,068		110,648,515

B. Basis for Amortization Charges

Account 404

	Balance to be Amortized	2009 Amortization	Balance to be amortized 12/31/09	Remaining months of amortization 12/31/09
(1)	48,000	12,000	36,000	36
(2)	12,324,719	488,214	11,743,090	-
(3)	18,182,596	6,272,786	18,391,530	-
(4)	5,475,561	288,067	5,187,493	216
TOTAL	36,030,876	7,061,068	35,358,113	

(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	04/12/2010	End of 2009/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		1.58	R4.0	21.80
13	311.00	138,632	100.00	-10.00	1.52	S1.0	23.30
14	312.10	80,391	60.00	-7.00	1.60	R3.0	22.60
15	312.20	451,397	70.00	-5.00	2.15	R1.5	22.30
16	312.30	4,208	25.00	20.00	2.53	R3.0	12.20
17	314.00	134,759	50.00	-5.00	2.54	S0.5	20.30
18	315.00	62,010	65.00	-7.00	5.47	S1.5	22.20
19	316.00	12,846	50.00	-5.00	6.14	R0.5	20.80
20	316.10	59	10.00	25.00	9.52	L2.5	7.60
21	316.40	248	10.00	25.00	4.71	L2.5	
22	316.50	83	10.00	25.00	5.06	L2.5	8.20
23	316.60	106	19.00	25.00	0.35	S2.0	12.00
24	316.70	80	19.00	25.00	3.88	S2.0	16.70
25	316.80	1,762	16.00	30.00	11.75	S0.0	9.30
26	317.000	3,586					
27	Subtotal Steam	890,370					
28	331.00	153,562	100.00	-25.00	2.70	R2.5	32.10
29	332.10	19,461	90.00	-20.00	2.27	S4.0	27.20
30	332.20	225,304	90.00	-20.00	2.21	S4.0	29.80
31	332.30	5,472			2.87	SQUARE	28.60
32	333.00	192,732	80.00	-5.00	1.90	R3.0	33.00
33	334.00	42,753	50.00	-5.00	2.95	R1.5	25.30
34	335.00	16,799	90.00		2.10	R2.0	30.50
35	335.10	48	15.00		1.93	SQUARE	12.30
36	335.20	393	20.00		3.56	SQUARE	10.70
37	335.30	720	5.00		12.62	SQUARE	2.00
38	336.00	7,493	75.00		1.91	R3.0	30.40
39	Subtotal Hydro	664,737					
40	341.00	7,170	35.00		3.47	SQUARE	30.40
41	342.00	4,446	35.00		3.05	SQUARE	32.40
42	343.00	92,651	35.00		3.02	SQUARE	29.70
43	344.00	39,093	35.00		2.93	SQUARE	33.80
44	345.00	24,899	35.00		2.57	SQUARE	28.30
45	346.00	3,054	35.00		3.03	SQUARE	29.50
46	Subtotal Other	171,313					
47	350.20	26,919	65.00		1.51	R3.0	54.20
48	352.00	43,095	60.00	-30.00	1.68	R3.0	47.30
49	353.00	304,154	45.00	-5.00	2.06	R1.0	35.40
50	354.00	139,305	65.00	-25.00	1.96	S3.0	48.60

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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	95,225	55.00	-60.00	2.81	R2.0	36.70
13	356.00	155,113	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	764,129					
16	361.00	27,551	65.00	-30.00	1.85	R2.5	52.60
17	362.00	181,364	50.00	-5.00	1.89	R0.5	42.10
18	364.00	217,059	44.00	-50.00	3.29	R1.5	31.50
19	365.00	121,129	47.00	-40.00	2.95	R0.5	35.10
20	366.00	48,299	60.00	-20.00	1.95	R2.0	51.20
21	367.00	186,974	50.00	-15.00	1.97	S0.5	41.10
22	368.00	401,884	37.00	5.00	1.67	R1.0	30.80
23	369.00	56,507	35.00	-40.00	3.09	R2.5	25.60
24	370.00	13,389	20.00		6.95	O1.0	11.90
25	370.10	22,481	15.00		6.76	S3.0	14.40
26	370.20	2,063	2.00		19.38	Square	0.50
27	370.30	41,109	3.00		25.67	Square	2.50
28	371.10	56	10.00	-5.00	3.68	S4.0	1.40
29	371.20	2,600	15.00	-5.00	0.63	R2.0	13.90
30	373.00	4,248	25.00	-25.00	4.09	R1.5	13.90
31	374.00	232					
32	Subtotal Distribution	1,326,945					
33	390.11	26,502	100.00	-5.00	2.38	S1.5	33.60
34	390.12	40,209	50.00	-5.00	2.24	L2.0	36.30
35	390.20	9,945	30.00		2.58	S3.0	20.80
36	391.10	14,254	20.00		4.97	SQUARE	10.30
37	391.20	21,416	5.00		24.37	SQUARE	2.10
38	391.21	5,156	7.00		13.96	L4.0	3.90
39	392.10	411	10.00	25.00	6.23	L2.5	5.90
40	392.30	2,580	8.00	50.00	8.62	S2.5	4.30
41	392.40	19,192	10.00	25.00	3.58	L2.5	7.30
42	392.50	614	10.00	25.00	1.49	L2.5	8.60
43	392.60	28,191	19.00	25.00	3.69	S2.0	12.00
44	392.70	3,934	19.00	25.00	2.39	S2.0	11.90
45	392.90	4,003	30.00	25.00	1.99	S1.5	21.10
46	393.00	1,331	25.00		5.40	SQUARE	9.70
47	394.00	5,250	20.00		4.84	SQUARE	11.70
48	395.00	11,551	20.00		5.39	SQUARE	10.20
49	396.00	9,241	16.00	30.00	6.95	S0.0	7.00
50	397.10	6,320	15.00		6.16	SQUARE	7.70

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	04/12/2010	End of 2009/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	397.20	15,702	15.00		6.99	SQUARE	9.60
13	397.30	3,271	15.00		8.36	SQUARE	6.60
14	397.40	2,101	10.00		8.20	SQUARE	5.60
15	398.00	4,225	15.00		9.57	SQUARE	6.90
16	Subtotal General	235,399					
17	Total Plant	4,052,893					
18							
19							
20							
21							
22							
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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) 04/12/2010	Year/Period of Report End of 2009/Q4

REGULATORY COMMISSION EXPENSES

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

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Federal Energy Regulatory Commission:				
2	Annual admin charges assessed by FERC	3,115,738		3,115,738	
3					
4	General Regulatory Expenses and				
5	Various other Dockets		1,498,991	1,498,991	
6					
7	Regulatory Commission Expenses - Idaho				
8	Rate Case - Misc expenses		35,798	35,798	
9					
10	Other- IPUC				
11	Amortization - rate related		25,757	25,757	
12	Intevenor Funding		40,000	40,000	
13	Other		14,628	14,628	
14					
15	Oregon Hydro - Fees Amortization	158,506		158,506	
16					
17	Regulatory Commission Expenses - Oregon				
18	Rate Case - Misc expenses		21,162	21,162	
19					
20	Other - OPUC				
21	AR - 538		29,054	29,054	
22	UM - 1401		44,688	44,688	
23	UE - 213		82,180	82,180	
24	UM - 1394		27,521	27,521	
25	UM - 1355		22,638	22,638	
26	UM - 1395		15,863	15,863	
27	UM - 1396		16,606	16,606	
28	Other matters less than $15,000		149,678	149,678	
29					
30					
31					
32					
33					
34					
35					
36					
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38					
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40					
41					
42					
43					
44					
45					
46	TOTAL	3,274,244	2,024,564	5,298,808	

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	3,115,738					2
							3
							4
Electric	928	1,498,991					5
							6
							7
Electric	928	35,798					8
							9
							10
Electric	928	25,757					11
Electric	928	40,000					12
Electric	928	14,628					13
							14
Electric	928	158,506					15
							16
							17
Electric	928	21,162					18
							19
							20
Electric	928	29,054					21
Electric	928	44,688					22
Electric	928	82,180					23
Electric	928	27,521					24
Electric	928	22,638					25
Electric	928	15,863					26
Electric	928	16,606					27
Electric	928	149,678					28
							29
							30
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		5,298,808					46

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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	04/12/2010	End of 2009/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

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

Classifications:

A. Electric R, D & D Performed Internally:
  (1) Generation
    a. hydroelectric
      i. Recreation fish and wildlife
      ii Other hydroelectric
    b. Fossil-fuel steam
    c. Internal combustion or gas turbine
    d. Nuclear
    e. Unconventional generation
    f. Siting and heat rejection
  (2) Transmission
    a. Overhead
    b. Underground
  (3) Distribution
  (4) Regional Transmission and Market Operation
  (5) Environment (other than equipment)
  (6) Other (Classify and include items in excess of $50,000.)
  (7) Total Cost Incurred

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

Line No.	Classification (a)	Description (b)
1	No R & D cost to report for 2009	
2		
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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) 04/12/2010	Year/Period of Report End of 2009/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	14,586,117		
4	Transmission	5,964,363		
5	Regional Market			
6	Distribution	16,805,306		
7	Customer Accounts	10,612,162		
8	Customer Service and Informational	4,063,116		
9	Sales			
10	Administrative and General	37,863,640		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	89,894,704		
12	Maintenance			
13	Production	7,419,562		
14	Transmission	3,022,496		
15	Regional Market			
16	Distribution	8,997,035		
17	Administrative and General	1,073,777		
18	TOTAL Maintenance (Total of lines 13 thru 17)	20,512,870		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	22,005,679		
21	Transmission (Enter Total of lines 4 and 14)	8,986,859		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	25,802,341		
24	Customer Accounts (Transcribe from line 7)	10,612,162		
25	Customer Service and Informational (Transcribe from line 8)	4,063,116		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	38,937,417		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	110,407,574		110,407,574
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 Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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)	110,407,574		110,407,574
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	44,206,030		44,206,030
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	44,206,030		44,206,030
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	Stores Expense - Clearing	4,381,594		4,381,594
79	Other Clearing accounts	2,676,835		2,676,835
80	Other Work in Progress	2,040,581		2,040,581
81	Paid Absences	18,902,009		18,902,009
82	Preliminary Survey and Investigation	338,985		338,985
83	Other Accounts	4,103,370		4,103,370
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	32,443,374		32,443,374
96	TOTAL SALARIES AND WAGES	187,056,978		187,056,978

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	04/12/2010	End of 2009/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: Idaho Power Company

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	5,235	27	8	4,128	229	700		178	
2	February	5,050	3	8	3,854	196	700		300	
3	March	5,021	11	8	3,576	195	700		550	
4	Total for Quarter 1	15,306			11,558	620	2,100		1,028	
5	April	4,537	14	8	2,328	151	700		1,358	
6	May	5,490	18	19	4,323	244	700		223	
7	June	5,744	29	19	4,431	274	1,004		35	
8	Total for Quarter 2	15,771			11,082	669	2,404		1,616	
9	July	6,045	22	20	4,718	303	1,004		20	
10	August	5,973	3	17	4,692	277	1,004			
11	September	5,628	3	16	4,299	278	1,004		47	
12	Total for Quarter 3	17,646			13,709	858	3,012		67	
13	October	4,427	14	21	3,141	141	1,004		141	
14	November	4,818	16	8	3,626	188	1,004			
15	December	5,423	9	8	4,178	241	1,004			
16	Total for Quarter 4	14,668			10,945	570	3,012		141	
17	Total Year to Date/Year	63,391			47,294	2,717	10,528		2,852	

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	04/12/2010	End of 2009/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	6,940,808
4	Nuclear	
5	Hydro-Conventional	8,096,365
6	Hydro-Pumped Storage	
7	Other	242,393
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	15,279,566
10	Purchases	2,911,842
11	Power Exchanges:	
12	Received	195,389
13	Delivered	327,800
14	Net Exchanges (Line 12 minus line 13)	-132,411
15	Transmission For Other (Wheeling)	
16	Received	4,133,976
17	Delivered	4,134,363
18	Net Transmission for Other (Line 16 minus line 17)	-387
19	Transmission By Others Losses	
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	18,058,610

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	13,948,280
23	Requirements Sales for Resale (See instruction 4, page 311.)	55,078
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	2,780,950
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
27	Total Energy Losses	1,274,302
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	18,058,610

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	04/12/2010	End of 2009/Q4

MONTHLY PEAKS AND OUTPUT

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

NAME OF SYSTEM: Idaho Power Company

Line No.	Month	Total Monthly Energy	Monthly Non-Requirments Sales for Resale & Associated Losses	MONTHLY PEAK		
				Megawatts (See Instr. 4)	Day of Month	Hour
	(a)	(b)	(c)	(d)	(e)	(f)
29	January	1,487,973	167,686	2,311	27	8 AM
30	February	1,252,297	113,475	2,160	2	8 AM
31	March	1,430,145	281,495	2,131	11	8 AM
32	April	1,506,565	445,362	1,904	1	8 AM
33	May	1,613,935	315,876	2,606	29	5 PM
34	June	1,520,541	319,884	2,760	29	7 PM
35	July	2,054,163	355,263	3,031	22	8 PM
36	August	1,662,052	118,163	2,987	3	6 PM
37	September	1,542,218	248,669	2,698	3	6 PM
38	October	1,348,727	274,622	1,870	29	8 AM
39	November	1,229,002	106,561	1,969	30	8 AM
40	December	1,410,992	33,894	2,528	10	8 AM
41	TOTAL	18,058,610	2,780,950			

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	04/12/2010	2009/Q4

FOOTNOTE DATA

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

Lucky Peak variation, (1,109)mwh, is the difference between energy generated and scheduled. The 747 mwh, is deviation received from Northwestern to true up the Salmon area load directly related to the control area. The net of these variations is (387) mwh.

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	04/12/2010	End of 2009/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			64.20		
6	Net Peak Demand on Plant - MW (60 minutes)	707			60		
7	Plant Hours Connected to Load	8760			5694		
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	4982609000			317400000		
13	Cost of Plant: Land and Land Rights	494358			106610		
14	Structures and Improvements	66127904			13781170		
15	Equipment Costs	424323763			57221112		
16	Asset Retirement Costs	0			0		
17	Total Cost	490946025			71108892		
18	Cost per KW of Installed Capacity (line 17/5) Including	637.1785			1107.6151		
19	Production Expenses: Oper, Supv, & Engr	155995			884620		
20	Fuel	87007677			5437088		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	4279803			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	2568382			0		
26	Misc Steam (or Nuclear) Power Expenses	5922253			175428		
27	Rents	452069			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	23060			2048845		
30	Maintenance of Structures	487528			0		
31	Maintenance of Boiler (or reactor) Plant	8300804			0		
32	Maintenance of Electric Plant	2544818			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	4467997			7273		
34	Total Production Expenses	116210386			8553254		
35	Expenses per Net KWh	0.0233			0.0269		
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	2736257	10488	0	185621	577	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	9225	140000	0	8338	138800	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	30.355	91.165	0.000	29.013	85.574	0.000
41	Average Cost of Fuel per Unit Burned	31.458	71.526	0.000	28.808	130.429	0.000
42	Average Cost of Fuel Burned per Million BTU	1.666	12.164	0.000	1.707	22.371	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.017	0.000	0.000	0.017	0.000	0.000
44	Average BTU per KWh Net Generation	10384.000	0.000	0.000	9882.000	0.000	0.000

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	04/12/2010	End of 2009/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
268	256	193	6
8550	822	637	7
0	261427	164159	8
0	0	0	9
0	0	0	10
0	8	4	11
1640799000	143846000	98506000	12
769351	402745	0	13
58723124	5699334	1458303	14
266404738	103765418	59489356	15
0	0	0	16
325897213	109867497	60947659	17
1149.5493	418.1367	352.7064	18
774252	147459	33183	19
37789767	11689400	7634101	20
0	0	0	21
3154907	0	0	22
0	0	0	23
0	0	0	24
0	175858	225686	25
2013880	114256	53858	26
62662	0	0	27
0	0	0	28
486	0	0	29
0	91192	97880	30
5375088	46501	467476	31
1050484	1439384	196820	32
163811	0	0	33
50385337	13704050	8709004	34
0.0307	0.0953	0.0884	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
Coal	Oil		Gas			Gas			36
Tons	Barrels		MCF			MCF			37
831165	8889	0	1458073	0	0	1026258	0	0	38
9551	138778	0	1038	0	0	1038	0	0	39
42.702	83.246	0.000	8.017	0.000	0.000	7.439	0.000	0.000	40
44.506	85.708	0.000	8.017	0.000	0.000	7.439	0.000	0.000	41
2.330	14.704	0.000	7.724	0.000	0.000	7.166	0.000	0.000	42
0.023	0.000	0.000	0.081	0.000	0.000	0.077	0.000	0.000	43
9708.000	0.000	0.000	10522.000	0.000	0.000	10814.000	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	04/12/2010	End of 2009/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)	110	75
7	Plant Hours Connect to Load	6,879	8,753
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	110	76
10	(b) Under the Most Adverse Oper Conditions	0	1
11	Average Number of Employees	4	5
12	Net Generation, Exclusive of Plant Use - Kwh	384,852,000	388,207,000
13	Cost of Plant		
14	Land and Land Rights	875,318	769,797
15	Structures and Improvements	11,807,207	1,039,638
16	Reservoirs, Dams, and Waterways	4,293,075	8,186,692
17	Equipment Costs	31,481,326	7,288,400
18	Roads, Railroads, and Bridges	839,276	486,477
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	49,296,202	17,771,004
21	Cost per KW of Installed Capacity (line 20 / 5)	534.0867	236.9467
22	Production Expenses		
23	Operation Supervision and Engineering	168,363	758,464
24	Water for Power	2,104,980	527,878
25	Hydraulic Expenses	88,898	420,705
26	Electric Expenses	45,290	73,740
27	Misc Hydraulic Power Generation Expenses	174,652	239,409
28	Rents	557	27,249
29	Maintenance Supervision and Engineering	139,653	87,961
30	Maintenance of Structures	118,114	76,730
31	Maintenance of Reservoirs, Dams, and Waterways	4,749	149,103
32	Maintenance of Electric Plant	437,787	75,255
33	Maintenance of Misc Hydraulic Plant	115,648	130,517
34	Total Production Expenses (total 23 thru 33)	3,398,691	2,567,011
35	Expenses per net KWh	0.0088	0.0066

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	04/12/2010	End of 2009/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
696	14	217	6
8,760	8,756	8,760	7
			8
747	15	221	9
220	1	202	10
7	2	7	11
2,406,922,000	44,848,000	1,046,958,000	12
			13
18,091,132	82,142	1,210,187	14
31,298,485	7,364,154	9,956,831	15
67,102,724	3,145,630	30,375,714	16
53,630,712	12,727,675	15,814,661	17
518,444	122,668	565,842	18
0	0	0	19
170,641,497	23,442,269	57,923,235	20
291.4956	1,887.4613	304.8591	21
			22
480,568	177,740	335,866	23
327,736	161,646	214,203	24
517,233	232,718	348,576	25
272,919	112,053	209,466	26
373,964	165,335	276,721	27
128,678	187	20,641	28
460,814	70,929	223,250	29
177,890	20,160	280,504	30
229,043	36	58,511	31
457,725	144,877	139,111	32
625,739	105,980	349,132	33
4,052,309	1,191,661	2,455,981	34
0.0017	0.0266	0.0023	35

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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)	440	24
7	Plant Hours Connect to Load	8,760	8,756
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	2,051,347,000	165,602,000
13	Cost of Plant		
14	Land and Land Rights	1,877,301	205,376
15	Structures and Improvements	2,413,190	2,764,626
16	Reservoirs, Dams, and Waterways	52,700,383	6,199,398
17	Equipment Costs	15,859,881	4,061,764
18	Roads, Railroads, and Bridges	819,192	304,683
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	73,669,947	13,535,847
21	Cost per KW of Installed Capacity (line 20 / 5)	188.1736	621.7661
22	Production Expenses		
23	Operation Supervision and Engineering	323,089	120,977
24	Water for Power	205,939	603,117
25	Hydraulic Expenses	337,561	113,049
26	Electric Expenses	215,688	58,757
27	Misc Hydraulic Power Generation Expenses	210,942	57,329
28	Rents	34,259	0
29	Maintenance Supervision and Engineering	291,498	54,188
30	Maintenance of Structures	171,922	16,572
31	Maintenance of Reservoirs, Dams, and Waterways	24,105	18,409
32	Maintenance of Electric Plant	277,322	97,900
33	Maintenance of Misc Hydraulic Plant	564,637	102,547
34	Total Production Expenses (total 23 thru 33)	2,656,962	1,242,845
35	Expenses per net KWh	0.0013	0.0075

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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
90	23	52	6
8,758	8,759	8,754	7
			8
91	24	53	9
84	14	50	10
5	3	5	11
479,830,000	131,562,000	171,666,000	12
			13
5,454,163	51,675	255,499	14
7,909,959	25,307,621	10,808,047	15
10,232,293	13,856,887	7,908,870	16
9,751,252	30,376,852	20,614,035	17
248,183	835,946	1,917,603	18
0	0	0	19
33,595,850	70,428,981	41,504,054	20
405.7470	2,817.1592	786.9559	21
			22
983,130	253,219	266,807	23
665,048	150,601	166,079	24
1,055,732	155,009	162,824	25
34,487	26,628	54,803	26
325,250	98,488	136,349	27
108,342	29,589	8,349	28
188,828	96,041	42,759	29
104,820	69,368	47,335	30
403,990	35,809	18,903	31
226,778	87,764	100,964	32
191,468	296,958	64,086	33
4,287,873	1,299,474	1,069,258	34
0.0089	0.0099	0.0062	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	04/12/2010	End of 2009/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	14
7	Plant Hours Connect to Load	8,760	8,539
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	227,484,000	99,792,000
13	Cost of Plant		
14	Land and Land Rights	202,399	313,328
15	Structures and Improvements	1,980,763	1,199,248
16	Reservoirs, Dams, and Waterways	5,557,358	512,402
17	Equipment Costs	7,828,260	4,508,878
18	Roads, Railroads, and Bridges	29,359	51,383
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	15,598,139	6,585,239
21	Cost per KW of Installed Capacity (line 20 / 5)	452.1200	526.8191
22	Production Expenses		
23	Operation Supervision and Engineering	395,908	213,795
24	Water for Power	209,100	142,055
25	Hydraulic Expenses	292,805	173,276
26	Electric Expenses	27,619	36,899
27	Misc Hydraulic Power Generation Expenses	182,360	109,811
28	Rents	0	221
29	Maintenance Supervision and Engineering	120,230	69,528
30	Maintenance of Structures	82,446	55,416
31	Maintenance of Reservoirs, Dams, and Waterways	91,613	70,621
32	Maintenance of Electric Plant	311,365	90,602
33	Maintenance of Misc Hydraulic Plant	137,115	70,544
34	Total Production Expenses (total 23 thru 33)	1,850,561	1,032,768
35	Expenses per net KWh	0.0081	0.0103

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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: 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	66	58	6
0	8,757	7,391	7
			8
0	64	61	9
0	60	1	10
0	7	2	11
0	266,346,000	162,666,000	12
			13
114,367	424,428	138,100	14
26,063,697	2,803,043	10,340,105	15
13,556,785	6,759,825	17,147,050	16
1,216,470	7,908,285	27,652,163	17
99,051	88,693	501,877	18
0	0	0	19
41,050,370	17,984,274	55,779,295	20
0.0000	299.7379	938.2556	21
			22
0	603,698	161,010	23
0	275,397	1,420,497	24
5,791,746	262,596	80,084	25
0	156,375	57,307	26
0	188,316	128,233	27
0	9,759	9,019	28
0	135,281	69,612	29
0	101,342	39,584	30
0	16,003	8,443	31
0	313,112	140,716	32
0	98,467	54,781	33
5,791,746	2,160,346	2,169,286	34
0.0000	0.0081	0.0133	35

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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	04/12/2010	End of 2009/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	16,326	1,756,730
3	Thousand Springs	1912	8.80	6.3	51,957	4,995,833
4						
5						
6	Internal Combustion:					
7	Salmon Diesel (1)	1967	5.00	4.2	41	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
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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
702,692	108,936		86,373			2
567,708	60,624		98,543			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
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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	Boardman	Slatt	500.00	500.00	S Tower	1.79		1
2								
3	Borah	Midpoint	345.00	500.00	S Tower	85.18		1
4	Jim Bridger	Goshen	345.00	345.00	S Tower	226.16		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	79.27		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	46.21		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	9.50		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	33.50		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	11.14		2
27	Caldwell	Ontario	230.00	230.00	H Wood	27.10		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	68.22		1
31	Danskin	Hubbard	230.00	230.00	H Steel	36.26		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	5.52		1
35	Hemingway	Bowmont	230.00	230.00	SP Steel	13.01		1
36					TOTAL	4,740.42	11.02	180

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	04/12/2010	End of 2009/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)	
2X1780 ACSR		446,708	446,708					1
								2
1272 ACSR	256,381	21,776,998	22,033,379					3
1272 ACSR	483,309	15,882,152	16,365,461					4
795 ACSR	571,979	11,047,483	11,619,462					5
1272 ACSR	344,220	6,028,033	6,372,253					6
715.5 ACSR	283,143	5,834,744	6,117,887					7
715.5 ACSR	64,851	10,494,526	10,559,377					8
715.5 ACSR	51,448	347,946	399,394					9
								10
795 ACSR	51,414	2,916,388	2,967,802					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	20,420,263	22,097,101					17
715.5 ACSR	413,793	2,090,601	2,504,394					18
715.5 ACSR								19
1272 ACSR	1,899	212,523	214,422					20
1590 ACSR	2,138,236	8,773,210	10,911,446					21
1272 ACSR	1,464,146	5,817,555	7,281,701					22
715.5 ACSR								23
1272 ACSR	3,062,812	6,580,815	9,643,627					24
795 AAC		80,895	80,895					25
954 ACSR	34,174	16,026,470	16,060,644					26
2X954 ACSR	197,658	5,890,623	6,088,281					27
1272 ACSR								28
1272 ACSR	81,701	1,666,354	1,748,055					29
1590 ACSR	624,917	22,457,621	23,082,538					30
1590 ACSR		10,451,149	10,451,149					31
1590 ACSR								32
1590 ACSR								33
1590 ACSR		3,528,033	3,528,033					34
1590 ACSR	1,852,599		1,852,599					35
	33,019,820	389,962,025	422,981,845					36

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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	Boise Bench	Midpoint #1	230.00	230.00	S Tower	0.86		1
2	Boise Bench	Midpoint #1	230.00	230.00	H Wood	108.24		1
3	Brownlee	Quartz Jct	230.00	230.00	S Tower	1.52		1
4	Brownlee	Quartz Jct	230.00	230.00	H Wood	41.80		1
5	Brownlee	Boise Bench #1 & #2	230.00	230.00	S Tower	99.97		2
6	Oxbow	Brownlee	230.00	230.00	S Tower	10.22		2
7	Boise Bench	Midpoint #2	230.00	230.00	S Tower	3.42		1
8	Boise Bench	Midpoint #2	230.00	230.00	H Wood	102.53		1
9	Oxbow	Pallette Jct	230.00	230.00	S Tower	20.21		2
10	Pallette Jct	Imnaha	230.00	230.00	H Wood	24.43		2
11	Hells Canyon	Palette Jct	230.00	230.00	S Tower	8.24		2
12	Brownlee	Boise Bench	230.00	230.00	S Tower	102.29		2
13	Boise Bench	Midpoint #3	230.00	230.00	H Wood	106.35		1
14	Palette Jct	Enterprise	230.00	230.00	H Wood	29.08		1
15	Borah	Brady #2	230.00	230.00	S Tower	0.41		1
16	Borah	Brady #2	230.00	230.00	H Wood	3.58		1
17	Borah	Brady #1	230.00	230.00	H Wood	3.98		1
18								
19	Goshen	State Line	161.00	161.00	H Wood	90.49		1
20	Don	Goshen	161.00	161.00	S Tower	2.39		2
21	Don	Goshen	161.00	161.00	H Wood	48.43		2
22								
23	American Falls Power Plant	Adelaide	138.00	138.00	H Wood	10.90		2
24	American Falls Power Plant	Adelaide	138.00	138.00	S P Wood	0.12		2
25	Minidoka Loop	Adelaide	138.00	138.00	S Tower	1.13		2
26	Nampa	Caldwell	138.00	138.00	S P Wood	10.72		2
27	Upper Salmon	Mountain Home Jct	138.00	138.00	H Wood	53.60		1
28	Upper Salmon	Cliff	138.00	138.00	H Wood	30.80		1
29	Eastgate	Russet	138.00	138.00	S P Wood	2.13		1
30	Brady	Fremont	138.00	138.00	S Tower	0.98		2
31	Brady	Fremont	138.00	138.00	H Wood	24.32		2
32	Brady	Fremont	138.00	138.00	S P Wood	24.34		2
33	King	Lower Malad	138.00	138.00	H Wood	84.91		2
34	Emmett Jct	Payette	138.00	138.00	H Wood	66.45		2
35	Mountain Home AFB Tap		138.00	138.00	H Wood	6.20		1
36					TOTAL	4,740.42	11.02	180

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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.
715.5 ACSR	336,186	4,085,707	4,421,893					1
715.5 ACSR								2
795 ACSR	53,068	2,139,082	2,192,150					3
795 ACSR								4
VARIOUS	289,934	7,991,044	8,280,978					5
1272 ACSR	14,810	1,182,550	1,197,360					6
715.5 ACSR	227,825	5,858,062	6,085,887					7
VARIOUS								8
1272 ACSR	23,308	2,075,244	2,098,552					9
1272 ACSR	138,477	1,392,628	1,531,105					10
1272 ACSR	10,737	1,252,130	1,262,867					11
954 ACSR	184,817	5,641,344	5,826,161					12
715.5 ACSR	247,857	5,392,037	5,639,894					13
1272 ACSR	51,122	1,749,361	1,800,483					14
1272 ACSR	3,068	231,823	234,891					15
715.5 ACSR								16
1272 ACSR	10,064	311,349	321,413					17
								18
250 COPPER	16,155	648,382	664,537					19
715.5 ACSR	76,041	1,652,914	1,728,955					20
397.5 ACSR								21
								22
250 COPPER	26,507	2,396,233	2,422,740					23
250 COPPER								24
715.5 ACSR	21,326	249,233	270,559					25
795 AAC	567,538	1,753,582	2,321,120					26
795 ACSR	47,687	2,457,857	2,505,544					27
795 ACSR	43,568	776,170	819,738					28
795 AAC	270,823	557,504	828,327					29
VARIOUS	564,932	3,706,706	4,271,638					30
VARIOUS								31
VARIOUS								32
VARIOUS	76,823	1,834,894	1,911,717					33
VARIOUS	30,918	2,507,989	2,538,907					34
397.5 ACSR	1,955		1,955					35
	33,019,820	389,962,025	422,981,845					36

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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	Ontario	Quartz	138.00	138.00	H Wood	73.34		1
2	King	American Falls PP	138.00	138.00	S Tower	1.03		2
3	King	American Falls PP	138.00	138.00	H Wood	148.63		1
4	King	American Falls PP	138.00	138.00	S P Wood	3.71		1
5	Duffin	Clawson	138.00	138.00	H Wood	6.22		1
6	American Falls	Brady Tie	138.00	138.00	H Wood	0.33		1
7	Upper Salmon A-B	King	138.00	138.00	H Wood	5.88		1
8	Upper Salmon B	Wells	138.00	138.00	H Wood	125.58		1
9	King	Wood River	138.00	138.00	H Wood	73.61		1
10	Boise Bench	Grove	138.00	138.00	S P Wood	10.44		2
11	Quartz	John Day	138.00	138.00	H Wood	67.32		1
12	Sinker Creek Tap		138.00	138.00	H Wood	2.79		1
13	Mora	Cloverdale	138.00	138.00	H Wood	2.57		1
14	Mora	Cloverdale	138.00	138.00	S P Wood	22.32		1
15	Mora	Cloverdale	138.00	138.00	S P Steel	0.96		2
16	Stoddard Jct	Stoddard Sub	138.00	138.00	S P Steel	3.80		1
17	Fossil Gulch Tap		138.00	138.00	H Wood	1.95		1
18	Wood River	Midpoint	138.00	138.00	H Wood	53.06		2
19	Wood River	Midpoint	138.00	138.00	S P Wood	16.69		2
20	Oxbow	McCall	138.00	138.00	H Wood	37.24		1
21	Oxbow	McCall	138.00	138.00	S P Wood	2.32		1
22	Lowell Jct	Nampa	138.00	138.00	S P Wood	7.58		2
23	Hunt	Milner	138.00	138.00	S P Wood	19.40		1
24	Strike	Bruneau Bridge	138.00	138.00	H Wood	13.48		1
25	American Falls	Kramer Sub	138.00	138.00	S P Wood	18.40		2
26	Pingree	Haven	138.00	138.00	S P Wood	11.72		1
27	Midpoint	Twin Falls	138.00	138.00	S P Wood	25.12		2
28	Twin Falls	Russett	138.00	138.00	S P Wood	1.73		1
29	Blackfoot	Aiken	46.00	138.00	S P Wood	6.18		2
30	Peterson	Tendoy	69.00	138.00	H Wood	57.22		1
31	Eastgate Tap	Eastgate	138.00	138.00	S P Wood	7.33		1
32	Boise Bench	Mora	138.00	138.00	H Wood	13.17		2
33	Bowmont-Caldwell	Simplot Sub	138.00	138.00	S P Wood	0.51		1
34	Gary Lane	Eagle	138.00	138.00	S P Wood	6.53		1
35	Locust Grove	Blackcat Sub	138.00	138.00	S P Steel	9.93	2.98	1
36					TOTAL	4,740.42	11.02	180

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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.
VARIOUS	34,428	1,948,970	1,983,398					1
715.5 ACSR	148,914	7,006,563	7,155,477					2
715.5 ACSR								3
715.5 ACSR								4
4\0	4,191	309,827	314,018					5
954 ACSR		96,921	96,921					6
250 COPPER	2,741	93,073	95,814					7
VARIOUS	28,490	2,093,136	2,121,626					8
VARIOUS	173,683	2,670,571	2,844,254					9
VARIOUS	225,602	1,652,772	1,878,374					10
397.5 ACSR	92,173	2,362,416	2,454,589					11
VARIOUS	20	77,199	77,219					12
715.5 ACSR	3,115,486	7,904,710	11,020,196					13
VARIOUS								14
795AAC								15
1272 ACSR								16
250 COPPER	450	63,439	63,889					17
397.5 ACSR	281,064	6,388,221	6,669,285					18
397.5 ACSR								19
397.5 ACSR	109,899	2,308,911	2,418,810					20
397.5 ACSR								21
715.5 ACSR	211,131	1,448,294	1,659,425					22
715.5 ACSR	3,324	1,190,604	1,193,928					23
397.5 ACSR	14,927	587,404	602,331					24
715.5 ACSR	13,734	1,052,549	1,066,283					25
397.5 ACSR	18,223	1,383,072	1,401,295					26
VARIOUS	54,848	2,958,765	3,013,613					27
715.5 ACSR	16,790	206,158	222,948					28
715.5 ACSR	13,616	476,381	489,997					29
397.5 ACSR	395,696	3,449,949	3,845,645					30
715.5 ACSR	207,645	1,058,897	1,266,542					31
715.5 ACSR	14,697	627,920	642,617					32
795 AAC		49,642	49,642					33
795 AAC	489,037	1,944,888	2,433,925					34
1272 ACSR	935,725	3,601,590	4,537,315					35
	33,019,820	389,962,025	422,981,845					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	04/12/2010	End of 2009/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	Boise Bench	Butler	138.00	138.00	S P Wood	0.18	4.02	1
2	Eagle	Star	138.00	138.00	S P Wood	6.35		1
3	Karcher Sub	Zilog Tap	138.00	138.00	S P Steel	2.08		1
4	Cloverdale - 712	712 - Wye	138.00	138.00	S P Steel	0.21	4.02	1
5	Butler	Wye	138.00	138.00	S P Steel	2.84		1
6	Horseflat	Starkey	138.00	138.00	H Wood	34.01		1
7	Starkey	Mccall	138.00	138.00	S P Steel	2.08		2
8	Starkey	Mccall	138.00	138.00	H Wood	3.80		1
9	Starkey	Mccall	138.00	138.00	S P Steel	1.50		1
10	Starkey	Mccall	138.00	138.00	S P Wood	17.61		1
11	Chestnut	Happy Valley	138.00	138.00	S P Steel	2.79		1
12	Garnet	Ward		138.00				
13	McCall	Lake Fork	138.00	138.00	S P Wood	8.84		1
14	McCall	Lake Fork	138.00	138.00	S Steel	2.90		
15	Caldwell	Willis	138.00	138.00	S P Steel	1.30		1
16	Caldwell	Willis	138.00	138.00	S P Steel	1.59		1
17	Caldwell	Willis	138.00	138.00	S P Wood	0.87		1
18	Valivue Tap		138.00	138.00	S P Steel	0.80		2
19	Kinport	Don #1	138.00	138.00	S Tower	1.44		2
20	Donn	HOKU	138.00	138.00	S P Steel	2.74		1
21	HOKU	Alamed	138.00	138.00	S P Steel	0.22		2
22	HOKU	Alamed	138.00	138.00	S P Steel	0.23		2
23	HOKU	Alamed	138.00	138.00	S P Steel	3.00		1
24	Twin Falls PP Tap		138.00	138.00	H Wood	0.82		1
25	American Falls PP	Amercian Falls Trans ST	138.00	138.00	S P Steel	0.37		1
26	Lower Salmon	King Tie	138.00	138.00	H Wood	0.22		1
27	C J Strike	Strike Jct	138.00	138.00	S Tower	4.30		2
28	Strike Jct	Mountain Home Jct	138.00	138.00	H Wood	23.51		1
29	Strike Jct	Bowmont		138.00	H Wood	0.05		1
30	Strike Jct	Bowmont	138.00	138.00	S Tower	0.36		1
31	Strike Jct	Bowmont	138.00	138.00	H Wood	68.23		1
32	Lucky Peak	Lucky Peak Jct	138.00	138.00	H Wood	4.48		2
33	Bliss	King	138.00	138.00	H Wood	10.44		1
34	Milner Deadend	Milner PP	138.00	138.00	S P Wood	1.30		1
35	Swan Falls Tap		138.00	138.00	H Wood	0.95		1
36					TOTAL	4,740.42	11.02	180

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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)
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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1272 ACSR	34,687	838,605	873,292					1
715.5 ACSR		3,133,215	3,133,215					2
795 AAC	43,035	443,805	486,840					3
1272 ACSR	140,412	709,148	849,560					4
795 ACSR	134,471	1,405,436	1,539,907					5
715.5 ACSR	638,405	19,998,719	20,637,124					6
715.5 ACSR								7
715.5 ACSR								8
715.5 ACSR								9
715.5 ACSR								10
1272 ACSR	78,579	1,821,921	1,900,500					11
	40,580		40,580					12
715.5 ACSR	331,539	4,687,415	5,018,954					13
								14
1272 ACSR	272,231	2,141,218	2,413,449					15
795 ACSR								16
795 ACSR								17
795 ACSR		351,497	351,497					18
715.5 ACSR	1,174	220,975	222,149					19
1272 ACSR		586	586					20
1272 ACSR								21
795 ACSR								22
795 ACSR								23
250 COPPER	58	53,889	53,947					24
715.5 ACSR		76,560	76,560					25
397.5 ACSR		4,406	4,406					26
715.5 ACSR	1,074	253,907	254,981					27
397.5 ACSR	4,355	2,274,613	2,278,968					28
715.5 ACSR	86,651	1,855,384	1,942,035					29
715.5 ACSR								30
								31
715.5 ACSR	7	279,481	279,488					32
715.5 ACSR	5,620	964,435	970,055					33
715.5 ACSR	2,814	183,606	186,420					34
397.5 ACSR	12,885	261,511	274,396					35
	33,019,820	389,962,025	422,981,845					36

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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								
3								
4	Hines	BPA (Harney)	115.00	115.00	H Wood	3.28		1
5								
6								
7	69 Kv Lines		69.00	69.00	H Wood	166.31		1
8	69 Kv Lines		69.00	69.00	S P Wood	922.54		1
9								
10								
11	46 Kv Lines		46.00	46.00	S P Wood	409.81		1
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	4,740.42	11.02	180

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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
								2
								3
397.5 ACSR	1,978	63,404	65,382					4
								5
								6
VARIOUS	1,540,670	41,095,960	42,636,630					7
VARIOUS								8
								9
								10
VARIOUS	177,279	10,686,433	10,863,712					11
								12
	5,736,253		5,736,253					13
								14
								15
								16
								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	33,019,820	389,962,025	422,981,845					36

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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	Donn	HOKU	2.74	SP Steel	18.98	1	1
7	HOKU	Alamed	0.22	SP Steel	22.73	2	2
8	HOKU	Alamed	0.23	SP Steel	21.74	2	2
9	HOKU	Alamed	3.00	SP Steel	19.34	1	1
10	Hemingway	Bowmont	13.01	SP Steel	7.30	1	2
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		49.84		169.07	13	14

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	04/12/2010	End of 2009/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
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)	No.
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
1272	ACSR	TAS 6'	138		331	255		586	6
1272	ACSR	TASDC 6'	138						7
795	ACSR	TASDC 6'	138						8
795	ACSR	TAS 6'	138						9
1590	ACSR	T-DC 12'	230	1,852,599				1,852,599	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
				1,875,550	7,807,276	7,830,151		17,512,977	44

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	04/12/2010	End of 2009/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	distribution	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	13.00	
14	Blackfoot	transmission	161.00	46.00	12.47
15	Blackfoot	distribution	161.00	138.00	12.98
16	Bliss - attended	transmission	138.00	13.80	
17	Blue Gulch	distribution	138.00	34.50	
18	Boise Bench - attended	distribution	138.00	34.50	
19	Boise Bench - attended	transmission	138.00	69.00	12.98
20	Boise Bench - attended	transmission	230.00	138.00	13.80
21	Boise	distribution	138.00	13.00	
22	Borah	transmission	345.00	230.00	13.80
23	Bowmont	distribution	69.00	46.00	6.90
24	Bowmont	distribution	138.00	34.50	
25	Bowmont	transmission	138.00	69.00	12.98
26	Brady	distribution	46.00	13.09	
27	Brady	transmission	230.00	138.00	13.80
28	Brady	transmission	138.00	46.00	12.47
29	Brady	distribution	69.00	13.00	
30	Brownlee - attended	transmission	230.00	13.80	
31	Bruneau Bridge	distribution	138.00	34.50	
32	Buckhorn	distribution	69.00	35.00	
33	Bucyrus	distribution	46.00	7.20	
34	Buhl	distribution	46.00	13.00	
35	Burley Rural	distribution	69.00	13.00	
36	Butler	distribution	138.00	13.00	
37	Caldwell	distribution	138.00	13.00	
38	Caldwell	transmission	138.00	69.00	12.47
39	Caldwell	transmission	230.00	138.00	12.50
40	Canyon Creek	distribution	138.00	35.00	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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.
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
50	3	1				14
80	1					15
69	3					16
15	1					17
42	2					18
75	3					19
494	4					20
67	3					21
450	3	1				22
8	3					23
18	1					24
50	2					25
		6				26
300	3					27
		1				28
		1				29
734	5	1				30
30	2					31
20	1					32
6	1	4				33
20	2					34
12	1					35
48	2					36
39	2	1				37
75	3					38
240	2					39
15	1					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	Canyon Creek	transmission	138.00	69.00	12.98
2	Cascade Power Plant - attended	transmission	69.00	4.60	
3	Cascade	Distribution	69.00	13.10	
4	Chestnut	distribution	138.00	13.00	
5	Clear Lake - attended	transmission	46.00	2.40	
6	Cliff	transmission	138.00	46.00	12.50
7	Cloverdale	Distribution	138.00	13.00	
8	Dale	distribution	46.00	13.00	
9	Dale	distribution	69.00	13.00	
10	Dale	distribution	138.00	36.20	
11	Dale	Transmission	138.00	46.00	12.50
12	Danskin	transmission	230.00	138.00	13.80
13	Danskin	distribution	18.00	4.16	
14	Danskin	transmission	138.00	12.00	
15	Don	distribution	138.00	7.60	
16	Don	distribution	138.00	13.20	
17	Don	distribution	138.00	13.00	
18	Don	distribution	14.00		
19	DRAM	distribution	138.00	13.00	
20	DRAM	transmission	230.00	138.00	13.80
21	Duffin	distribution	138.00	34.50	
22	Eagle	distribution	138.00	13.00	
23	Eastgate	distribution	138.00		
24	Eastgate	distribution	138.00	13.00	
25	Eckert	distribution	138.00	36.20	
26	Eden	distribution	138.00	36.20	
27	Eden	transmission	138.00	46.00	12.98
28	Elkhorn	distribution	138.00	12.47	
29	Elmore	distribution	138.00	35.00	
30	Elmore	transmission	138.00	69.00	12.50
31	Emmett	distribution	138.00	12.50	
32	Emmett	Transmission	138.00	69.00	12.50
33	Falls	distribution	46.00	13.00	
34	Filer	distribution	46.00	13.00	
35	Flying H	distribution	69.00	2.40	
36	Fort Hall	distribution	46.00	13.00	
37	Fossil Gulch	distribution	138.00	35.00	
38	Fremont	transmission	138.00	46.00	12.50
39	Gary	distribution	138.00	13.00	
40	Gem	distribution	69.00	13.00	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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.
15	1					1
12	1					2
10	1					3
48	2					4
4	1					5
16	3	1				6
48	2					7
		7				8
		1				9
27	1	1				10
25	1					11
320	2					12
6	1					13
96	2					14
		1				15
108	6	3				16
26	1	1				17
80	6					18
134	8					19
160	2					20
36	2					21
38	2					22
24	1					23
18	1	1				24
18	1					25
24	1					26
15	1					27
15	2					28
17	1					29
30	2					30
24	1					31
25	1					32
18	2					33
10	1					34
15	2					35
10	1	1				36
15	1					37
50	3	1				38
37	2					39
18	2					40

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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	Goodng Rural	distribution	46.00	13.00	
2	Golden Valley	distribution	69.00	13.00	
3	Gowen Substation	distribution	138.00	35.00	
4	Grindstone	distribution	35.00	12.50	
5	Grove	distribution	138.00	13.09	
6	Hagerman	distribution	46.00	13.00	
7	Hagerman	distribution	46.00	13.00	32.00
8	Hailey	distribution	138.00	13.00	
9	Happey Valley	distribution	138.00	13.09	
10	Haven	distribution	138.00	35.00	
11	Haven	transmission	138.00	46.00	
12	Hewlett Packard	distribution	138.00	13.10	
13	Hidden Springs	distribution	138.00	13.09	
14	Highland	distribution	138.00	13.09	
15	Hill	distribution	138.00	13.00	
16	Hillsdale	distribution	138.00		
17	Homedale	distribution	69.00	13.00	
18	Horse Flat	transmission	230.00	138.00	13.80
19	Horse Flat	distribution	69.00	13.00	
20	Horseshoe Bend	distribution	35.00	12.50	
21	Horseshoe Bend	distribution	69.00	36.20	
22	Horseshoe Bend	distribution	69.00	25.00	
23	Huston	distribution	69.00	13.00	
24	Hulen	distribution	46.00	13.00	
25	Hunt	transmission	230.00	138.00	13.80
26	Hydra	distribution	138.00	36.20	
27	Island	distribution	69.00	13.00	
28	Jerome	distribution	138.00	13.00	
29	Julion Clawson	distribution	138.00	34.50	
30	Joplin	distribution	138.00	13.00	
31	Joplin	distribution	138.00	35.00	
32	Karcher	distribution	138.00	13.09	
33	Kenyon	distribution	69.00	13.00	
34	Ketchum	distribution	138.00	13.00	
35	Kinport	transmission	161.00	46.00	13.20
36	Kinport	transmission	230.00	138.00	12.47
37	Kinport	transmission	230.00	138.00	13.80
38	Kinport	transmission	345.00	230.00	13.80
39	Kramer	distribution	138.00	34.50	
40	Kramer	distribution	138.00	13.00	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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.
15	2					1
10	1	1				2
24	1					3
5	2					4
72	3					5
10	1					6
5	1					7
20	1					8
18	1					9
12	1					10
25	1					11
20	1					12
8	1					13
18	1					14
24	1	1				15
24	1					16
20	2					17
100	1					18
	1					19
5	1					20
12	1					21
5	1					22
10	1					23
10	1					24
300	3					25
48	2					26
12	1					27
40	2					28
30	2					29
15	1					30
18	1					31
12	1					32
20	2					33
42	2					34
		7				35
180	1					36
180	1					37
600	3	1				38
12	1					39
18	1					40

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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	Kuna	distribution	138.00	13.00	
2	Lake Fork	distribution	138.00	36.20	
3	Lake Fork	transmission	138.00	69.00	12.50
4	Lamb	distribution	138.00	13.09	
5	Lansing	distribution	69.00	13.00	
6	Lincoln	distribution	138.00	13.00	
7	Linden	distribution	138.00	13.00	
8	Locust	distribution	138.00	36.20	
9	Locust	transmission	230.00	138.00	13.80
10	Lower Malad - attended	transmission	138.00	7.20	
11	Lower Salmon - attended	transmission	138.00	13.80	
12	Map Rock	distribution	69.00	13.00	
13	McCall	distribution	13.00	13.09	
14	McCall	distribution	138.00	36.20	
15	Meridian	distribution	138.00	13.00	
16	Micron	distribution	138.00	13.00	
17	Midpoint	transmission	230.00	138.00	13.80
18	Midpoint	transmission	345.00	230.00	13.80
19	Midpoint	transmission	500.00	345.00	
20	Midrose	distribution	138.00	13.09	
21	Milner	distribution	138.00	69.00	12.47
22	Milner	distribution	69.00	46.00	6.90
23	Milner	distribution	138.00	35.00	
24	Milner PP - attended	transmission	138.00	13.80	
25	Moonstone	distribution	138.00	35.00	
26	Mora	distribution	138.00	34.50	
27	Moreland	distribution	35.00	13.00	6.00
28	Moreland	distribution	46.00	13.00	
29	Moreland	distribution	46.00	35.00	12.50
30	Mountain Home	distribution	69.00	12.50	
31	Mountain Home Air Force Base	distribution	69.00	13.00	
32	Mountain Home Air Force Base	distribution	138.00	13.00	
33	Nampa	distribution	230.00	138.00	13.80
34	Nampa	distribution	138.00	13.00	
35	New Meadows	distribution	138.00	36.20	
36	New Plymouth	distribution	69.00	13.00	
37	Notch Butte	distribution	13.00	13.09	
38	Orchard	distribution	69.00	36.20	
39	Orchard	distribution	69.00	35.00	12.47
40	Parma	distribution	69.00	12.50	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
15	1					1
18	1					2
15	1					3
18	1					4
12	1					5
10	1					6
33	2					7
48	2					8
360	2					9
16	1					10
70	4					11
10	1					12
12	1					13
18	1					14
36	2					15
48	4					16
120	1					17
720	2					18
750	3	1				19
24	1	1				20
100	4					21
8	3	1				22
17	1					23
36	1					24
12	1					25
39	2					26
1						27
8	1					28
13	4					29
15	1					30
		1				31
18	1					32
180	1					33
50	3					34
12	1					35
10	1					36
10	1					37
6	1					38
10	3					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	04/12/2010	End of 2009/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	Parma	distribution	69.00	34.50	
2	Paul	distribution	138.00	34.50	12.50
3	Payette	distribution	138.00	13.00	
4	Pingree	transmission	138.00	46.00	12.50
5	Pingree	distribution	138.00	35.00	
6	Pleasant Valley	distribution	138.00	34.50	
7	Pocatello	distribution	46.00	12.50	
8	Poleline	distribution	138.00	13.09	
9	Portneuf	distribution	138.00	36.20	
10	Portneuf	distribution	46.00	35.00	
11	Rockford	distribution	46.00	13.00	
12	Russett	distribution	138.00	13.00	
13	Sailor Creek	distribution	138.00	2.40	
14	Sailor Creek	distribution	138.00	35.00	
15	Salmon	distribution	69.00	13.00	
16	Salmon	distribution	69.00	34.50	12.50
17	Salmon	transmission	13.00	2.40	5.00
18	Shoshone	distribution	46.00	13.00	
19	Shoshone	distribution	46.00	7.20	
20	Shoshone Falls - attended	transmission	46.00	2.30	
21	Shoshone Falls - attended	transmission	46.00	6.60	
22	Silver	distribution	138.00	34.50	
23	Simplot	distribution	138.00	13.00	
24	Sinker Creek	distribution	138.00	34.50	
25	Siphon	distribution	138.00	34.50	
26	South Park	distribution	46.00	13.00	
27	Star	distribution	138.00	13.00	
28	Starkey	Transmission	138.00	69.00	12.50
29	State	distribution	69.00	13.00	
30	Stoddard	distribution	138.00	13.00	
31	Strike Power Plant - attended	transmission	138.00	13.80	
32	Sugar	distribution	138.00	34.50	
33	Swan Falls - attended	transmission	138.00	6.90	
34	Taber	distribution	46.00	13.00	
35	Ten Mile	distribution	138.00	13.09	
36	Terry	distribution	138.00	13.00	
37	Thousand Springs - attended	transmission	46.00	7.20	
38	Thousand Springs - attended	transmission	7.00	2.40	
39	Toponis	distribution	138.00	33.00	
40	Twin Falls	distribution	138.00	13.00	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
12	1					1
36	2					2
23	3					3
50	3					4
22	2					5
42	2					6
36	2					7
18	1					8
18	1					9
		1				10
14	2					11
18	1					12
15	2					13
15	1					14
10	1	4				15
10	3	1				16
2						17
10	1					18
2	3					19
3	1					20
10	1					21
12	1					22
15	1					23
12	1					24
33	2					25
10	1					26
18	1					27
18	1					28
33	2					29
15	1					30
83	3					31
20	2					32
18	1					33
5	1					34
24	1					35
42	3					36
8	1					37
2	1					38
18	1					39
44	2					40

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/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	Twin Falls	transmission	138.00	46.00	12.98
2	Twin Falls PP - attended	transmission	138.00	7.20	
3	Twin Falls PP - attended	transmission	138.00	13.20	
4	Upper Malad - attended	transmission	45.00	7.20	
5	Upper Salmon- attended	transmission	138.00	7.20	
6	Ustick	distribution	138.00	13.00	
7	Vallivue	distribution	138.00	13.09	
8	Victory	distribution	138.00	13.00	
9	Ware	distribution	69.00	13.00	
10	Weiser	distribution	69.00	13.00	
11	Weiser	transmission	138.00	69.00	12.47
12	Wilder	distribution	69.00	13.00	
13	Willis	distribution	138.00	13.09	
14	Wye	distribution	138.00	13.00	
15	Zilog	distribution	138.00	13.09	
16					
17					
18	The above are all State of Idaho				
19					
20	Montana:				
21	Peterson	transmission	230.00	69.00	13.20
22					
23	Nevada:				
24	Valmy - attended	transmission	345.00	21.30	
25	Wells	transmission	138.00	69.00	13.00
26					
27	Oregon:				
28	Boardman - attended	transmission	500.00	24.00	
29	Cairo	distribution	69.00	13.00	
30	Hells Canyon - attended	transmission	230.00	13.80	
31	Hells Canyon	distribution	69.00	0.50	1.00
32	Hines	transmission	138.00	115.00	12.47
33	Malheur Butte	distribution	69.00	34.50	12.50
34	Nyssa	distribution	69.00	13.00	
35	Ontario	distribution	138.00	13.00	
36	Ontario	transmission	138.00	69.00	12.50
37	Ontario	transmission	230.00	138.00	13.80
38	Ore-Ida	distribution	69.00	13.00	
39	Oxbow - attended	transmission	138.00	69.00	13.00
40	Oxbow - attended	transmission	230.00	13.80	

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	04/12/2010	End of 2009/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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
33	2					1
9	1					2
72	1					3
8	1					4
36	4					5
44	2					6
18	1					7
24	1					8
12	1	1				9
20	2					10
25	1					11
10	1					12
18	1					13
56	3					14
24	1					15
						16
						17
						18
						19
						20
30	3	1				21
						22
						23
150	1					24
20	3	1				25
						26
						27
55	1					28
12	1					29
501	4					30
						31
40	1					32
8	3	1				33
20	2					34
38	2					35
75	3	2				36
240	2					37
15	1					38
10	3	1				39
244	2					40

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/12/2010	Year/Period of Report End of 2009/Q4

SUBSTATIONS

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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	Oxbow - attended	transmission	230.00	138.00	13.80
2	Quartz	transmission	138.00	69.00	12.50
3	Quartz	transmission	230.00	138.00	13.00
4	Vale	distribution	69.00	13.09	
5					
6	Wyoming:				
7	Jim Bridger - attended	transmission	345.00	22.00	
8					
9					
10					
11					
12					
13					
14	Transformers-distribution substations under 10,000				
15	KVA 88 unattended.				
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)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Number of Units (j)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Total Capacity (In MVa) (k)	Line No.
100	1					1
30	2					2
100	3	1				3
10	1					4
						5
						6
748	1					7
						8
						9
						10
						11
						12
						13
						14
353						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
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						38
						39
						40

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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) 04/12/2010	Year/Period of Report End of 2009/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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

Line No.	Description of the Non-Power Good or Service (a)	Name of Assiciated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Managerial Expenses which includes labor & taxes	IdaCorp	417420	427,645
22				
23	Affiliates - Ida-West, Ierco			
24	IdaCorp Financial Services, IdaCorp Energy			
25	Do not meet the $250,000 threshold			
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

IDAHO POWER COMPANY

2009 FERC FORM 1

ANNUAL REPORT

IDAHO SECTION FOLLOWS

ANNUAL REPORT

IDAHO SUPPLEMENT TO FERC FORM 1

MULTI-STATE ELECTRIC COMPANIES

INDEX

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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	$ 993,232,456	$ 910,245,287
3	Operating Expenses			
4	Operation Expenses (401)	15	613,147,331	550,991,682
5	Maintenance Expenses (402)	15	64,769,922	64,078,869
6	Depreciation Expense (403)		96,284,156	89,690,866
7	Amort. & Depl. of Utility Plant (404-405)		6,307,117	4,622,992
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)
13	Taxes Other Than Income Taxes (408.1)	2	18,952,082	17,214,058
14	Income Taxes - Federal (409.1)	2	14,745,212	(1,876,222)
15	- Other (409.1)	2	1,466,739	(5,091,963)
16	Provision for Deferred Income Taxes (410.1 & 411.1) Net	2	12,847,159	41,638,625
17	Investment Tax Credit Adj. - Net (411.4)	2	223,185	2,343,614
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)		828,742,902	759,831,509
24				
25	Net Utility Operating Income (Enter Total of line 2 less 23)			
26	(Carry forward to page 11, line 27)		$ 164,489,555	$ 150,413,778

TAXES ALLOCATED TO IDAHO

Kind of Tax	Taxes Charged During Year
Taxes Other Than Income Taxes:	
Labor Related:	
FICA	$ 11,450,632
FUTA	71,113
State Unemployment	452,013
Payroll Deduction & Loading	(11,973,757)
Total Labor Related	0
Property Taxes	15,834,861
Kilowatt-hour Tax	1,522,379
Licenses	3,467
Regulatory Commission Fees	1,347,232
Irrigation PIC	244,144
Total Taxes Other Than Income Taxes	18,952,082
Federal Income Taxes	14,745,212
State Income Taxes	1,466,739
Deferred Income Taxes	12,847,159
Investment Tax Credit Adjustment - Net	223,185
Total Taxes Allocated to Idaho	$ 48,234,376

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)	$ 1,549,041	$ 636,667
2	Customer Accounts Receivable (Account 142)	64,433,173	76,792,157
3	Other Accounts Receivable (Account 143)	6,557,937	9,087,713
4	(Disclose any capital stock subscription received)		
5	Total	$ 72,540,152	$ 86,516,536
6			
7	Less: Accumulated Provision for Uncollectible		
8	Accounts-Cr. (Account 144)	1,723,936	1,990,343
9			
10	Total, Less Accumulated Provision for		
11	Uncollectible Accounts	$ 70,816,216	$ 84,526,193
12			
13			
14	Notes Receivable - Account 141: (at 12-31-09)		
15	Directors, officers, and employees - $ 64,154		
16			
17			
18	Other Accounts Receivable - Account 143: (at 12-31-09)		
19	Directors, officers, and employees - $ 4,014		
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	$ 1,723,936	$	$		1,723,936
23	Prov. for uncollectibles					
24	for year	266,407				266,407
25	Accounts written off					
26	Coll. of accounts					
27	written off					
28	Adjustments (explain)					
29						
30						
31						
32	Balance end of year	$ 1,990,343	$ -	$ -	$ -	$ 1,990,343
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..................................	$ 26,579,771	$ 38,970,228	$ 46,655,898	$ 18,894,101	
4						
5						
6						
7						
8						
9						
10	Total Account 145..................	26,579,771	38,970,228	46,655,898	18,894,101	
11						
12	Account 146:					
13						
14						
15						
16	IDACORP, Inc.........................	$ (2,011)	$ 3,661,882	$ 3,659,871	$ -	
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31	Total Account 146......................	$ (2,011)	$ 3,661,882	$ 3,659,871	$ -	
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					
5					
6	Northern SWIP Sale	3,036,684	3/30/2009	$ 122,587	
7					
8					
9					
10					
11					
12					
13					
14	Total gain	$ 3,036,684		$ 122,587	
15					
16					
17	Transmission Line #103	*	2/3/2009		$ (3,973)
18					
19					
20					
21					
22					
23	* Land purchased in 1942. Could not identify				
24	original cost in asset records				
25					
26					
27					
28					
29					
30					
31	Total loss	$ 0			$ (3,973)

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	ACCENTIENT INC	Computer Support Services	$ 19,600
2	ADECCO	Staffing Services	32,478
3	AERO-GRAPHICS	Mapping Services	101,076
4	ATER, WYNNE LLP	Legal Services	296,322
5	BARKER, ROSHOLT & SIMPSON LLP	Legal Services	414,833
6	BRENNEMAN, JOHN	Lobby Services	73,626
7	BROWNSTEIN HYATT FARBER SCHREC	Legal Services	719,840
8	BUREAU OF LAND MANAGEMENT	Environmental Services	209,284
9	CADMUS GROUP INC, THE	Architect Services	24,025
10	CASCADE ENERGY ENGINEERING INC	Engineering Services	81,401
11	CEDARCRESTONE INC	Computer Support Services	72,143
12	CHASAN & WALTON TRUST ACCOUNT	Legal Services	400,000
13	CHURCH, JOHN S	Economic Services	12,000
14	COLLEGE OF IDAHO	Environmental Services	13,500
15	COLLEGE OF SOUTHERN IDAHO	Environmental Services	10,000
16	COMSYS INFORMATION TECHNOLOGY	Computer Support Services	194,160
17	CONNOR CLAIMS SPECIALISTS	Insurance Services	11,029
18	CORNERSTONE SYSTEMS INC	Computer Support Services	91,400
19	CSHQA	Architect Services	126,704
20	DAVIS WRIGHT TREMAINE LLP	Legal Services	389,082
21	DELOITTE & TOUCHE LLP	Accounting Services	642,989
22	DEWEY & LEBOEUF	Legal Services	3,308,496
23	DHI INC	Environmental Services	38,235
24	ECOANALYSTS INC	Environmental Services	107,928
25	ECOS CONSULTING	Consulting Services	42,238
26	ECOTOPE	Architect Services	30,256
27	EMC CORPORATION	Computer Support Services	86,073
28	ENERNOC INC	Consulting Services	451,808
29	EVANS KEANE	Legal Services	12,471
30	GLAHE & ASSOCIATES INC	Environmental Services	34,487
31	GLOBAL INSIGHT	Environmental Services	25,934
32	GOLDER ASSOCIATES	Environmental Services	101,373
33	HARDESTY, REBECCA	Environmental Services	76,470
34	HDR SSR ENGINEERS	Engineering Services	24,166
35	HONEYWELL INTERNATIONAL INC	Environmental Services	17,419
36	HYQUAL	Environmental Services	59,054
37	IDAHO DEPARTMENT OF FISH AND G	Environmental Services	100,000
38	INTELLIBIND LLC	Consulting Services	82,285
39	INTERWOVEN INC	Computer Support Services	20,429
40	IOWA INSTITUTE OF HYDRAULICS	Consulting Services	15,425
41	JACO ENVIRONMENTAL INC	Environmental Services	17,916
42	JONES AND SWARTZ PLLC	Legal Services	158,355
43	JUB ENGINEERS	Engineering Services	15,880
44	MAINLINE INFORMATION SYSTEMS I	Computer Support Services	424,425
45	MAUPIN, COX & LEGOY INC	Legal Services	18,529

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	MCCLURE ENGINEERING	Engineering Services	$ 48,459
47	MCDOWELL & RACKNER PC	Legal Services	429,332
48	MIRANDE, MICHAEL	Legal Services	57,819
49	MOODY'S ANALYTICS INC	Financial Services	26,500
50	MUSGROVE ENGINEERING PA	Engineering Services	88,779
51	NEXANT INC	Computer Support Services	29,702
52	NIELSEN GROUP INC, THE	Consulting Services	227,326
53	ORACLE CORPORATION	Computer Support Services	219,677
54	OREGON DEPARTMENT OF ENERGY	Consulting Services	143,866
55	PAINE, HAMBLEN, COFFIN , BROOK	Management Services	292,698
56	PANTER, GREGORY W	Legal Services	33,000
57	PARAGON CONSULTING SERVICES	Consulting Services	30,295
58	PARR BROWN GEE & LOVELESS INC	Legal Services	36,794
59	PARR WADDOUPS BROWN GEE AND LO	Environmental Services	40,390
60	PEAK SCIENCE COMMUNICATIONS	Management Services	42,964
61	PLANNEDSCAPE	Consulting Services	18,917
62	PORTLAND ENERGY CONSERVATION,	Environmental Services	213,411
63	POWER ENGINEERS INC	Engineering Services	45,359
64	PROFESSIONAL TRAINING SYSTEMS	Management Services	17,575
65	PUBLIC OPINION STRATEGIES LLC	Management Services	17,750
66	R W BECK	Consulting Services	64,650
67	RIDDELL WILLIAMS P.S.	Legal Services	50,451
68	RIPLEY, LARRY D	Legal Services	13,650
69	RIVERSIDE TECHNOLOGY INC	Management Services	13,000
70	ROGER WRIGHT CONSULTING ENGINE	Engineering Services	13,791
71	S G S STATISTICAL SERVICES	Consulting Services	14,250
72	SALDIN, TOM	Legal Services	27,000
73	SALLADAY & DAVIS	Legal Services	31,584
74	SHARP & SMITH INC.	Legal Services	15,692
75	SMITH, CURTIS D	Legal Services	49,890
76	SOFTWARE AG INC	Computer Support Services	91,775
77	SOS STAFFING SERVICES	Management Services	20,661
78	SPHERION STAFFING AND RECRUITI	Management Services	88,485
79	SPINK BUTLER LLP	Legal Services	20,851
80	STEPHAN, KVANVIG, STONE & TRAI	Legal Services	22,018
81	STEPTOE & JOHNSON LLP	Legal Services	394,668
82	STOEL RIVES LLP	Legal Services	211,579
83	SULLIVAN & CROMWELL	Management Services	544,421
84	TEKSYSTEMS	Computer Support Services	51,675
85	TETRA TECH INC	Consulting Services	12,715
86	TIMBERLINE SURVEYING PLLC	Surveying Services	17,258
87	TOWERS PERRIN HR SERVICES	Management Services	45,140
88	TREASURE VALLEY LEGAL SERVICES	Legal Services	205,645
89	TROUT, JONES, GLEDHILL, FUHRMA	Legal Services	38,958

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	UNIVERSITY OF IDAHO	Environmental Services	284,065
91	VAN NESS FELDMAN	Legal Services	218,582
92	VAN WINKLE ENVIRONMENTAL CONSU	Environmental Services	87,148
93	WEATHER MODIFICATION INC	Cloud Seeding Services	384,716
94	WHITE PETERSON TRUST ACCOUNT	Legal Services	50,000
95	YTURRI& ROSE& BURNHAM& BENTZ	Legal Services	35,649
1	TOTAL		14,385,724

PROFESSIONAL OR CONSULTATIVE SERVICES

ITEMS $5,000 OR MORE BUT LESS THAN $10,000

Line No.	PAYEE	PREDOMINANT NATURE OF SERVICE	AMOUNT
1	A TREEHOUSE	Computer/Printer Supplies	5,295
2	Accrue AP-PropertyServices	Property Serivces	7,777
3	ASHGROVE CEMENT	Construction Services	9,538
4	BERGLES LAW LLC	Legal Services	6,840
5	BOISE STATE UNIVERSITY	Environmental Services	5,000
6	BRASSEY, WETHRELL, & CRAWFORD,	Legal Services	5,649
7	BROWN RUDNICK BERLACK ISRAELS	Lobby Services	6,000
8	CTA ARCHITECTS	Architect Services	8,571
9	DC ENGINEERING, PC	Engineering Services	9,105
10	DESERT RESEARCH INSTITUTE	Environmental Services	9,521
11	ENERTECH SERVICES	Consulting Services	9,000
12	ERNST & YOUNG LLP	Accounting Services	6,000
13	HERITAGE ENVIRONMENTAL CONSULT	Environmental Services	7,855
14	HOPKINS RODEN CROCKETT HANSEN	Lobby Services	6,000
15	JEROME CHEESE CO	Management Services	8,438
16	JONES CHARTERED	Legal Services	6,633
17	KPMG LLP	Accounting Services	8,364
18	M J BRADLEY & ASSOCIATES LLC	Consulting Services	5,812
19	MODULA4 INC	Computer Support Services	9,972
20	PERKINS COIE LLP	Legal Services	9,821
21	PHONE PRO	Management Services	5,000
22	RAIN SHADOW RESEARCH, INC	Consulting Services	8,834
23	REYNOLDSON GROUP PLLC	Legal Services	7,473
24	SAWTOOTH TECHNICAL SERVICES, I	Computer Support Services	7,927
25	SOFTWARE HOUSE	Computer Support Services	8,901
26	STATISTICAL DESIGN	Consulting Services	5,040
27	STRUCTURED	Engineering Services	9,800
28	UNIVERSITY OF TEXAS AT DALLAS	Environmental Services	7,985
29	WEATHER DECISION TECHNOLOGIES	Meteorological Services	7,968
30	WENGLIKOWSKI, RICHARD F.	Surveying Services	8,109
31	WRUBLE WILDLAND SERVICES	Environmental Services	5,576
32			
33			
34			
35			
36			
37			
38			
39			
40			
41			
40			
41			
42			
43			
44			
45	**TOTAL**		233,804

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	$ 51,819	
3	(302) Franchises and Consents	20,695,155	
4	(303) Miscellaneous Intangible Plant	30,625,097	
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	51,372,071	
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	4,378,761	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	846,472,518	
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)	651,906,341	
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
			$ (42,600)	(301)	2
			20,610,043	(302)	3
			32,188,432	(303)	4
			52,755,874		5
					6
					7
				(310)	8
				(311)	9
				(312)	10
				(313)	11
				(314)	12
				(315)	13
				(316)	14
			3,639,403	(317)	15
			850,081,599		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
			663,043,595		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)	$ 157,012,463	
46	TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 45)	1,655,391,322	
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	29,508,846	
49	(352) Structures and Improvements	35,140,814	
50	(353) Station Equipment	242,900,194	
51	(354) Towers and Fixtures	117,045,225	
52	(355) Poles and Fixtures	77,089,121	
53	(356) Overhead Conductors and Devices	126,757,259	
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices		
56	(359) Roads and Trails	259,733	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	628,701,192	
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	4,477,141	
61	(361) Structures and Improvements	23,233,750	
62	(362) Station Equipment	158,476,358	
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	193,280,200	
65	(365) Overhead Conductors and Devices	108,838,821	
66	(366) Underground Conduit	46,743,899	
67	(367) Underground Conductors and Devices	176,439,252	
68	(368) Line Transformers	347,244,209	
69	(369) Services	52,673,244	
70	(370) Meters	56,487,653	
71	(371) Installations on Customer Premises	2,319,885	
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	3,943,911	
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,174,158,323	
76	5. GENERAL PLANT		
77	(389) Land and Land Rights	10,029,463	
78	(390) Structures and Improvements	66,136,218	
79	(391) Office Furniture and Equipment	42,518,018	
80	(392) Transportation Equipment	54,120,844	
81	(393) Stores Equipment	1,095,243	
82	(394) Tools, Shop, and Garage Equipment	4,453,928	
83	(395) Laboratory Equipment	9,922,115	
84	(396) Power Operated Equipment	8,033,807	
85	(397) Communication Equipment	24,184,365	
86	(398) Miscellaneous Equipment	3,803,267	
87	SUBTOTAL (Enter Total of lines 77 thru 86)	224,297,268	
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)	224,297,268	
91	TOTAL (Accounts 101 and 106)	3,733,920,176	
92	(102) Electric Plant Purchased		
93	(Less) (102) Electric Plant Sold		
94	(103) Experimental Plant Unclassified		
95			
96	TOTAL Electric Plant in Service	$ 3,733,920,176	

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
			$ 163,688,832		45
			1,676,814,026		46
					47
			26,355,337	(350)	48
			36,874,135	(352)	49
			259,189,976	(353)	50
			118,781,110	(354)	51
			78,699,437	(355)	52
			130,470,816	(356)	53
				(357)	54
				(358)	55
			259,091	(359)	56
				(359.1)	57
			650,629,901		58
					59
			4,464,403	(360)	60
			25,428,370	(361)	61
			171,224,978	(362)	62
				(363)	63
			198,384,439	(364)	64
			112,606,744	(365)	65
			47,630,314	(366)	66
			183,885,941	(367)	67
			365,533,296	(368)	68
			53,584,402	(369)	69
			76,159,662	(370)	70
			2,428,221	(371)	71
				(372)	72
			4,035,560	(373)	73
				(374)	74
			1,245,366,330		75
					76
			9,965,131	(389)	77
			70,985,209	(390)	78
			37,805,449	(391)	79
			54,565,482	(392)	80
			1,232,339	(393)	81
			4,861,786	(394)	82
			10,696,887	(395)	83
			8,556,954	(396)	84
			25,366,534	(397)	85
			3,912,553	(398)	86
			227,948,323		87
				(399)	88
				(399.1)	89
			227,948,323		90
			3,853,514,454		91
				(102)	92
				(102)	93
				(371)	94
					95
			$ 3,853,514,454		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)	OPERATING REVENUES Amount for Previous Year (c)
1	Sales of Electricity		
2	(440) Residential Sales	$ 396,249,589	$ 341,596,320
3	(442) Commercial and Industrial Sales		
4	Small (or Commercial)(See Instr. 4) (1)	326,270,298	294,564,569
5	Large (or Industrial)(See Instr. 4) (2)	130,739,702	113,125,182
6	(444) Public Street and Highway Lighting	3,115,326	2,784,169
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	856,374,915 *	752,070,239
11	(447) Sales for Resale - Opportunity....Non-Firm Only	86,951,072	113,059,123
12	TOTAL Sales of Electricity	943,325,987	865,129,362
13	(449) Provision for Rate Refunds	(2,333,063)	(5,876,173)
14	TOTAL Revenue Net of Provision for Refunds	940,992,924	859,253,189
15	**Other Operating Revenues**		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	3,738,436	3,611,150
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	16,297,224	16,916,322
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	32,203,871	30,464,627
22			
23			
24			
25	TOTAL Other Operating Revenues	52,239,531	50,992,098
26	TOTAL Electric Operating Revenues	$ 993,232,456	$ 910,245,287

(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
5,094,579,185	5,093,471,949	391,759	389,177	2
				3
5,260,695,289	5,648,670,010	76,494	75,605	4
2,889,807,183	3,101,515,627	120	114	5
30,137,604	29,990,161	1,353	1,237	6
				7
				8
				9
13,275,219,261 **	13,873,647,747	469,726	466,133	10
2,689,972,558	1,946,246,652	N/A	N/A	11
15,965,191,819	15,819,894,399	469,726	446,889	12
				13

* Includes $ 6,293,431 unbilled revenues.

** Includes -1,375,287 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	$ 1,730,026	$ 1,585,144
5	(501) Fuel	123,530,408	108,989,376
6	(502) Steam Expenses	7,051,991	6,491,790
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	2,436,169	2,002,446
10	(506) Miscellaneous Steam Power Expenses	7,732,363	7,681,857
11	(507) Rents	490,668	281,610
12	(509) Allowances		
13	TOTAL Operation (Enter Total of lines 4 thru 12)	142,971,625	127,032,223
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	1,975,511	2,456,682
16	(511) Maintenance of Structures	464,737	618,172
17	(512) Maintenance of Boiler Plant	12,971,894	13,885,052
18	(513) Maintenance of Electric Plant	3,410,225	5,395,860
19	(449) Provision for Rate Refunds	4,422,214	5,650,640
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	23,244,580	28,006,406
21	TOTAL Power Production Expenses-Steam Power (Enter Total of lines 13 and 20)	166,216,205	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	4,996,334	4,984,055
45	(536) Water for Power	6,839,199	4,814,932
46	(537) Hydraulic Expenses	9,622,038	9,016,462
47	(538) Electric Expenses	1,400,051	1,323,535
48	(539) Miscellaneous Hydraulic Power Generation Expenses	2,561,153	2,690,247
49	(540) Rents	359,232	399,555
50	TOTAL Operation (Enter Total of lines 44 thru 49)	25,778,007	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	$ 1,975,236	$ 1,785,723
54	(542) Maintenance of Structures	1,331,517	1,220,450
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,079,628	515,125
56	(544) Maintenance of Electric Plant	2,819,107	1,988,155
57	(545) Maintenance of Miscellaneous Hydraulic Plant	2,832,668	2,630,881
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	10,038,157	8,140,333
59	TOTAL Power Production Expenses-Hydraulic Power (Enter Total of lines 50 and 58)	35,816,164	31,369,119
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	331,668	325,262
63	(547) Fuel	18,336,546	18,492,527
64	(548) Generation Expenses	385,488	363,281
65	(549) Miscellaneous Other Power Generation Expenses	305,054	442,565
66	(550) Rents	0	-
67	TOTAL Operation (Enter Total of lines 62 thru 66)	19,358,755	19,623,635
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	0	-
70	(552) Maintenance of Structures	185,036	209,865
71	(553) Maintenance of Generating and Electric Plant	497,807	40,597
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	1,630,541	614,836
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	2,313,384	865,298
74	TOTAL Power Production Expenses-Other Power (Enter Total of lines 67 and 73)	21,672,139	20,488,934
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	152,316,715	288,699,422
77	(556) System Control and Load Dispatching	12,528	73,778
78	(557) Other Expenses	73,149,445	(112,995,170)
79	TOTAL Other Power Supply Expenses (Enter Total of lines 76 thru 78)	225,478,687	175,778,030
80	TOTAL Power Production Expenses (Enter Total of lines 21, 41, 59, 74, and 79)	449,183,196	382,674,713
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,146,091	1,987,843
84	(561) Load Dispatching	2,232,972	2,806,393
85	(562) Station Expenses	1,658,377	1,491,967
86	(563) Overhead Line Expenses	763,563	784,669
87	(564) Underground Line Expenses		
88	(565) Transmission of Electricity by Others	6,287,468	9,936,576
89	(566) Miscellaneous Transmission Expenses	327,409	529,755
90	(567) Rents	1,324,828	990,555
91	TOTAL Operation (Enter Total of lines 83 thru 90)	14,740,708	18,527,758
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	499,815	376,412
94	(569) Maintenance of Structures	327,684	387,193
95	(570) Maintenance of Station Equipment	2,556,220	2,473,911
96	(571) Maintenance of Overhead Lines	2,471,315	1,987,795
97	(572) Maintenance of Underground Lines		
98	(573) Maintenance of Miscellaneous Transmission Plant	32	2,151
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	5,855,065	5,227,462
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	20,595,774	23,755,220
101	3. DISTRIBUTION EXPENSES		
102	Operation		
103	(580) Operation Supervision and Engineering	3,141,623	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	$ 3,014,735	$ 2,906,722
106	(582) Station Expenses	1,072,819	1,066,301
107	(583) Overhead Line Expenses	3,169,511	3,172,327
108	(584) Underground Line Expenses	1,885,378	2,085,453
109	(585) Street Lighting and Signal System Expenses	128,093	141,411
110	(586) Meter Expenses	4,309,928	4,332,721
111	(587) Customer Installations Expenses	1,217,628	1,227,727
112	(588) Miscellaneous Distribution Expenses	4,682,137	5,187,236
113	(589) Rents	288,975	604,482
114	TOTAL Operation (Enter Total of lines 103 thru 113)	22,910,827	23,865,402
115	Maintenance		
116	(590) Maintenance Supervision and Engineering	290,469	246,198
117	(591) Maintenance of Structures	23,673	-
118	(592) Maintenance of Station Equipment	3,166,911	3,322,976
119	(593) Maintenance of Overhead Lines	13,336,846	11,557,647
120	(594) Maintenance of Underground Lines	1,066,017	1,328,521
121	(595) Maintenance of Line Transformers	373,749	154,268
122	(596) Maintenance of Street Lighting and Signal Systems	476,614	453,194
123	(597) Maintenance of Meters	685,447	888,231
124	(598) Maintenance of Miscellaneous Distribution Plant	244,352	114,582
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	19,664,077	18,065,618
126	TOTAL Distribution Expenses (Enter Total of lines 114 and 125)	42,574,904	41,931,019
127	4. CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision	357,284	435,360
130	(902) Meter Reading Expenses	5,092,915	5,146,950
131	(903) Customer Records and Collection Expenses	12,604,114	7,866,032
132	(904) Uncollectible Accounts	5,092,669	1,876,639
133	(905) Miscellaneous Customer Accounts Expenses	533	320
134	TOTAL Customer Accounts Expenses (Enter Total of lines 129 thru 133)	23,147,516	15,325,300
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision	257,106	299,100
138	(908) Customer Assistance Expenses	40,542,279	21,710,324
139	(909) Informational and Instructional Expenses	15,511	0
140	(910) Miscellaneous Customer Service and Informational Expenses	836,024	876,111
141	TOTAL Cust. Service and Informational Expenses (Enter Total of lines 137 thru 140)	41,650,920	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	57,849,175	46,724,352
152	(921) Office Supplies and Expenses	11,682,289	16,697,245
153	(Less) (922) Administrative Expenses Transferred-Credit	(26,136,870)	(26,005,639)

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)
154	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
155	(923) Outside Services Employed	$ 7,093,497	$ 10,542,564
156	(924) Property Insurance	3,046,423	2,957,019
157	(925) Injuries and Damages	6,381,755	5,113,519
158	(926) Employee Pensions and Benefits	29,122,006	26,159,168
159	(927) Franchise Requirements	3,196	1,200
160	(928) Regulatory Commission Expenses	4,579,316	5,332,170
161	(929) Duplicate Charges-Cr.		
162	(930.1) General Advertising Expenses	148,379	487,897
163	(930.2) Miscellaneous General Expenses	3,340,110	3,282,233
164	(931) Rents	1,009	10,731
165	TOTAL Operation (Enter Total of lines 151 thru 164)	97,110,285	91,302,458
166	Maintenance		
167	(935) Maintenance of General Plant	3,654,659	3,498,047
168	TOTAL Admin and General Expenses (Enter Total of lines 165-167)	100,764,944	94,800,506
169	TOTAL Elec Op and Maint Exp (Total of 80, 100, 126, 134, 141, 148, 168)	$ 677,917,253	$ 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, 2009	December 31, 2008
2	Total Regular Full-Time Employees	1,979	2,006
3	Total Part-Time and Temporary Employees	24	20
4	Total Employees	2,003	2,026

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