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

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

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2008 APR 17 PM 8: 13
IDAHO PUBLIC
UTILITIES COMMISSION

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

Exact Legal Name of Respondent (Company)	Year/Period of Report
Idaho Power Company	End of 2007/Q4

IDAHO POWER®
An IDACORP Company

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IDAHO PUBLIC
UTILITIES COMMISSION

April 18, 2008

Idaho Public Utilities Commission
472 West Washington Street
Boise, ID 83720

To Whom It May Concern:

Enclosed is an original and two copies of Idaho Power Company's Annual Report FERC Form 1, which includes the "Idaho Section" covering Idaho operations.

Also enclosed, as additional information for your use, is one copy each:

- FERC Form 1, with "Idaho Section" unbound
- IDACORP Inc. and Idaho Power Company SEC Form 10-K

Each year a copy of the EIA-860 is also included, however, this year the Department of Energy is modifying the software used to generate the report. There is no indication when the report will be available.

The above reports are for the year ended December 31, 2007.

Yours very truly,

Darrel Anderson

Darrel Anderson
Senior Vice President - Administrative
Services and Chief Financial Officer

DA:dva
Enclosure

P.O. Box 70 (83707)
1221 W. Idaho St.
Boise, ID 83702

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, 2007, and the related statements of income—regulatory basis; retained earnings—regulatory basis; cash flows—regulatory basis, and accumulated comprehensive income, comprehensive income, and hedging activities—regulatory basis for the year ended December 31, 2007, 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 Idaho Power Company as of December 31, 2007, and the results of its operations and its cash flows for the year ended December 31, 2007, 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 Idaho Power 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 27, 2008

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q)is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

(1) one million megawatt hours of total annual sales,
(2) 100 megawatt hours of annual sales for resale,
(3) 500 megawatt hours of annual power exchanges delivered, or
(4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: http://www.ferc.gov/docs-filing/eforms/form-1/elec-subm-soft.asp. The software is used to submit the electronic filing to the Commission via the Internet.

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

(d) For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

a) Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Reference Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

e) The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of _____ for the year ended on which we have reported separately under date of ___________ , we have also reviewed schedules __________________ of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases."

The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at http://www.ferc.gov/help/how-to.asp.

(g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from http://www.ferc.gov/docs-filing/eforms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/eforms.asp#3Q-gas .

IV. When to Submit:

FERC Forms 1 and 3-Q must be filed by the following schedule:

a) FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,144 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 150 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions** (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and" firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

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.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

(3) 'Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

(4) 'Person' means an individual or a corporation;

(5) 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; ......

(11) "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

(a) To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development -costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

General Penalties

The Commission may assess up to $1 million per day per violation of its rules and regulations. *See* FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

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 2007/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 1221 W Idaho Street, P.O. Box 70 Boise, ID 83707-0070	
05 Name of Contact Person Darrel Anderson	06 Title of Contact Person Senior VP of Admin Ser & CFO
07 Address of Contact Person *(Street, City, State, Zip Code)* 1221 W Idaho Street, P.O. Box 70 Boise, ID 83707-0070	

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(208) 388-2650	(1) ☒ An Original (2) ☐ A Resubmission	04/11/2008

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Darrel Anderson	Darrel Anderson	04/11/2008
02 Title Senior VP of Admin ser & CFO		

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

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

LIST OF SCHEDULES (Electric Utility)

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

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

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	04/11/2008	End of 2007/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Substations	426-427	
68	Footnote Data	450	
	Stockholders' Reports Check appropriate box: [X] Four copies will be submitted [ ] No annual report to stockholders is prepared		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2008	End of 2007/Q4

GENERAL INFORMATION

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

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

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

Idaho, June 30, 1989

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

Not Applicable

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

Class of Utility Service	State
Electric	Idaho
"	Oregon

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2008	End of 2007/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	04/11/2008	End of 2007/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	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	04/11/2008	End of 2007/Q4

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1			
2	President and Chief Executive Officer	J. LaMont Keen	500,000
3			
4	Sr Vice President, Administrative Services & CFO	Darrel T. Anderson	310,000
5			
6	Sr Vice President, Power Supply	James C. Miller	295,000
7			
8	Sr Vice President, General Counsel and Secretary	Thomas Saldin	285,000
9			
10	Sr Vice President, Delivery	Dan Minor	270,000
11			
12	Vice President, Regulatory Affairs	Ric Gale	220,000
13			
14	Vice President and Chief Information Officer	Dennis Gribble	188,000
15			
16	Vice President, Human Resources	Luci McDonald	190,000
17			
18	Vice President, Public Affairs	Greg Panter	195,000
19			
20	Vice President and Treasurer	Steven R. Keen	210,000
21			
22	Vice President and Chief Risk Officer	Lori Smith	185,000
23			
24	Vice President, Engineering and Operations	Lisa Grow	165,000
25			
26	Vice President, Customer Service and Regional Ops	Warren Kline	165,000
27			
28	Vice President, Audit and Compliance	Naomi Crafton-Shankel	142,000
29			
30	Corporate Secretary	Patrick Harrington	155,000
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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	04/11/2008	End of 2007/Q4

DIRECTORS

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

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Rotchford L. Barker (1)	P.O. Box 2080, Cody, Wyoming 82414
2		
3	Judith A Johansen	2786 Glenmorrie Dr. Lake Oswego, Oregon 97034
4		
5	Christine King	AMI Semiconductor, Inc.
6		2300 Buckskin Rd M/S #3, Pocatello, Idaho 83201
7		
8	Gary Michael ***	P.O. Box 1718, Boise, Idaho 83701
9		
10	Jon H. Miller ***	P.O. Box 1557, Boise, Idaho 83701
11		
12	Peter S. O'Neill ***	100 N. 9th St., Suite 200, Boise, Idaho 83702
13		
14	Jan B. Packwood	900 W. Bogus View Drive, Eagle, Idaho 83616
15		
16	J. LaMont Keen, President and Chief Executive Officer**	Idaho Power Company, 1221 W. Idaho Street,
17		P.O. Box 70, Boise, Idaho 83707-0070
18		
19	Richard G. Reiten	Pacwest Center, 1211 SW Fifth Ave., Suite 1600
20		Portland, Oregon 97204
21		
22	Joan Smith	2309 S.W. First Avenue, No. 1141, Portland, Oregon 97201
23		
24	Robert A. Tinstman ***	4433 W. Quail Point Court, Boise, Idaho 83703
25		
26	Thomas Wilford	Alscott Inc, P.O. Box 70001, Boise, Idaho 83701
27		
28		
29	(1) Retired in May 17, 2007.	
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2008	End of 2007/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

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

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

1. Relicensing costs closed to account 302 - $60,000 to Shoshone Bannock Tribe for distribution line right-of-way - Idaho.

2. None

3. None

4. None

5. New Transmission Lines:

Borah to Hunt	230Kv	68.24 miles
Horse Flat to McCall 1	38Kv	34.56 miles
Bennett Mtn to Danskin Power	230Kv	5.51 miles

Additions to Existing Lines:
Taps added to Spring Valley, Cartwright and Hidden Spring Substations 138Kv 9.69 miles.

Distribution Stations:

Spring Valley Substation	138Kv
Starkey Substation	138/69Kv

6. On June 22,2007, IPC issued $140 million of its 6.30% First Mortgage Bonds, Secured Medium-Term Notes, Series F, due June 15,2037. IPC used the net proceeds to pay down outstanding commercial paper, which had increased to $164 million in June 2007 because of increased capital expenditures. Commission Authorization IPUC IPC-E-07-06, OPUC UF4238 and WPSC 2005-30-ES-7.

On October 18,2007, IPC issued $100 million of its 6.25% First Mortgage Bonds, Secured Medium-Term Notes, Series G, due October 15,2037. IPC used the net proceeds to retire $80 million of 7.38% First Mortgage Bonds due December 1,2007, and paid down outstanding commericial paper. Commission Authorization IPUC IPC-E-06-28, OPUC UF 4211 and WPSC 20005-ES-4-27.

7. None

8. On December 29, 2007 a general wage increase of 3.25%.

9. See Pages 123.15 to 123.20

10. None

11. None

12. None

13. Refer to pages 104 & 105 for changes in officers and directors. There were a number of changes in Major Security Holders in 2006. The top ten institutional shareholders list saw one change from 3rd quarter to 4th quarter. In the 4th quarter Thales Fund Management replaced Brandwine Global Investment Mgmt on the top ten list.

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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2008	End of 2007/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	3,799,704,789	3,586,503,680
3	Construction Work in Progress (107)	200-201	257,589,900	210,094,019
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		4,057,294,689	3,796,597,699
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	1,468,831,768	1,406,209,952
6	Net Utility Plant (Enter Total of line 4 less 5)		2,588,462,921	2,390,387,747
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)		2,588,462,921	2,390,387,747
15	Utility Plant Adjustments (116)	122	0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		888,877	976,937
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	55,937,107	51,914,196
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)		4,846	3,696
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		28,071,727	28,039,959
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		33,160	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		84,935,717	80,934,788
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		2,908,319	1,189,450
36	Special Deposits (132-134)		44,840,534	510,000
37	Working Fund (135)		35,850	57,850
38	Temporary Cash Investments (136)		2,403,000	1,157,000
39	Notes Receivable (141)		5,975,468	6,717,530
40	Customer Accounts Receivable (142)		62,122,209	54,218,159
41	Other Accounts Receivable (143)		7,080,171	10,081,728
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		1,305,058	968,073
43	Notes Receivable from Associated Companies (145)		21,527,626	9,154,480
44	Accounts Receivable from Assoc. Companies (146)		0	0
45	Fuel Stock (151)	227	17,267,629	15,173,831
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	41,370,751	36,762,206
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

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	1,898,952	2,316,011
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		9,119,846	8,952,014
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		611	0
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		36,314,344	31,365,181
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		586,202	0
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		33,160	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)		252,113,294	176,687,367
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		13,390,497	9,786,336
70	Extraordinary Property Losses (182.1)	230	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230	0	0
72	Other Regulatory Assets (182.3)	232	448,227,917	378,846,883
73	Prelim. Survey and Investigation Charges (Electric) (183)		454,153	416,116
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)		480,899	361,477
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	73,222,183	124,388,934
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	36,000	0
81	Unamortized Loss on Reaquired Debt (189)		13,548,821	14,760,653
82	Accumulated Deferred Income Taxes (190)	234	106,047,151	117,138,886
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		655,407,621	645,699,285
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		3,580,919,553	3,293,709,187

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Rresubmission	04/11/2008	end of 2007/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	97,877,030	97,877,030
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)	252	0	0
5	Stock Liability for Conversion (203, 206)	252	0	0
6	Premium on Capital Stock (207)	252	581,757,435	530,757,435
7	Other Paid-In Capital (208-211)	253	0	0
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254	2,096,925	2,096,925
11	Retained Earnings (215, 215.1, 216)	118-119	388,826,291	354,624,872
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	53,474,014	49,451,103
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)	-6,156,500	-5,737,123
16	Total Proprietary Capital (lines 2 through 15)		1,113,681,345	1,024,876,392
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,115,460,000	955,460,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	30,521,364	31,585,000
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		3,409,345	3,097,272
24	Total Long-Term Debt (lines 18 through 23)		1,142,572,019	983,947,728
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)		660,554	665,706
29	Accumulated Provision for Pensions and Benefits (228.3)		81,470,279	78,643,708
30	Accumulated Miscellaneous Operating Provisions (228.4)		916,667	0
31	Accumulated Provision for Rate Refunds (229)		2,397,165	1,227,492
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)		14,514,992	12,911,220
35	Total Other Noncurrent Liabilities (lines 26 through 34)		99,959,657	93,448,126
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		136,585,000	52,200,001
38	Accounts Payable (232)		81,922,232	83,697,801
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		724,321	1,110,966
41	Customer Deposits (235)		1,159,232	1,125,192
42	Taxes Accrued (236)	262-263	2,845,258	40,225,757
43	Interest Accrued (237)		18,761,346	12,324,003
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Rresubmission	04/11/2008	end of 2007/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)		2,534,420	2,015,825
48	Miscellaneous Current and Accrued Liabilities (242)		59,832,828	19,404,370
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		171,234	1,462,637
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)		304,535,871	213,566,552
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		33,261,676	26,085,511
57	Accumulated Deferred Investment Tax Credits (255)	266-267	71,000,710	69,113,142
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	20,838,443	50,242,704
60	Other Regulatory Liabilities (254)	278	203,756,794	225,731,042
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)		535,627,552	573,951,058
64	Accum. Deferred Income Taxes-Other (283)		55,685,486	32,746,932
65	Total Deferred Credits (lines 56 through 64)		920,170,661	977,870,389
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		3,580,919,553	3,293,709,187

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

STATEMENT OF INCOME

Quarterly
1. Enter in column (d) the balance for the reporting quarter and in column (e) the balance for the same three month period for the prior year.
2. Report in column (f) the quarter to date amounts for electric utility function; in column (h) the quarter to date amounts for gas utility, and in (j) the quarter to date amounts for other utility function for the current year quarter.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in (k) the quarter to date amounts for other utility function for the prior year quarter.
4. If additional columns are needed place them in a footnote.

Annual or Quarterly if applicable
5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.
8. Report data for lines 8, 10 and 11 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1 and 407.2.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	875,401,235	930,618,611		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	532,394,837	566,729,405		
5	Maintenance Expenses (402)	320-323	68,163,077	64,719,689		
6	Depreciation Expense (403)	336-337	94,999,200	90,803,410		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	8,095,753	9,089,661		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	-22,723	-22,723		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		21,246	10,391,371		
13	(Less) Regulatory Credits (407.4)		-2,093,195			
14	Taxes Other Than Income Taxes (408.1)	262-263	17,633,417	18,661,413		
15	Income Taxes - Federal (409.1)	262-263	2,627,990	52,572,378		
16	- Other (409.1)	262-263	-6,572,551	5,194,257		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	44,230,688	-2,231,898		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	9,243,213	6,646,675		
19	Investment Tax Credit Adj. - Net (411.4)	266	1,887,569	326,869		
20	(Less) Gains from Disp. of Utility Plant (411.6)			46,144		
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		2,754,122	8,257,817		
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)		753,554,363	801,283,196		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		121,846,872	129,335,415		

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
875,401,235	930,618,611					2
						3
532,394,837	566,729,405					4
68,163,077	64,719,689					5
94,999,200	90,803,410					6
						7
8,095,753	9,089,661					8
-22,723	-22,723					9
						10
						11
21,246	10,391,371					12
-2,093,195						13
17,633,417	18,661,413					14
2,627,990	52,572,378					15
-6,572,551	5,194,257					16
44,230,688	-2,231,898					17
9,243,213	6,646,675					18
1,887,569	326,869					19
	46,144					20
						21
2,754,122	8,257,817					22
						23
						24
753,554,363	801,283,196					25
121,846,872	129,335,415					26

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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) 04/11/2008	Year/Period of Report End of 2007/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		121,846,872	129,335,415		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		2,706,143	2,273,822		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		2,066,936	2,001,750		
33	Revenues From Nonutility Operations (417)		102,798	117,924		
34	(Less) Expenses of Nonutility Operations (417.1)		-515,188	374,582		
35	Nonoperating Rental Income (418)		-2,553	-318		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	4,022,911	9,648,253		
37	Interest and Dividend Income (419)		3,819,829	3,108,574		
38	Allowance for Other Funds Used During Construction (419.1)		5,995,175	6,092,152		
39	Miscellaneous Nonoperating Income (421)		6,514,689	5,189,612		
40	Gain on Disposition of Property (421.1)		321,364	2,738		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		21,928,608	24,056,425		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)					
44	Miscellaneous Amortization (425)	340				
45	Donations (426.1)	340	478,611	573,834		
46	Life Insurance (426.2)		-200,209	-547,211		
47	Penalties (426.3)		919,811	2,307		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		886,146	1,267,336		
49	Other Deductions (426.5)		4,528,200	6,954,457		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		6,612,559	8,250,723		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	35,980	35,742		
53	Income Taxes-Federal (409.2)	262-263	1,749,032	-4,206,660		
54	Income Taxes-Other (409.2)	262-263	370,373	92,071		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	1,552,871	1,234,191		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	1,905,495	1,955,602		
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)		1,802,761	-4,800,258		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		13,513,288	20,605,960		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		58,097,082	53,744,453		
63	Amort. of Debt Disc. and Expense (428)		1,081,816	1,023,500		
64	Amortization of Loss on Reaquired Debt (428.1)		1,211,832	1,184,936		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)	340		83,415		
68	Other Interest Expense (431)	340	5,987,546	4,002,342		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		7,597,141	4,026,460		
70	Net Interest Charges (Total of lines 62 thru 69)		58,781,135	56,012,186		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		76,579,025	93,929,189		
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)		76,579,025	93,929,189		

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	04/11/2008	End of 2007/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		353,080,906	319,909,317
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	FIN 48 Adjustment		15,135,588	
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)		15,135,588	
16	Balance Transferred from Income (Account 433 less Account 418.1)		72,556,114	84,280,936
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	-53,490,283	(51,109,347)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-53,490,283	(51,109,347)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		387,282,325	353,080,906
	APPROPRIATED RETAINED EARNINGS (Account 215)			

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
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)		388,826,291	354,624,872
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		49,451,103	39,802,850
50	Equity in Earnings for Year (Credit) (Account 418.1)		4,022,911	9,648,253
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)		53,474,014	49,451,103

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	76,579,025	93,929,189
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	94,999,200	90,803,410
5	Amortization of	12,500,338	14,660,508
6			
7			
8	Deferred Income Taxes (Net)	35,380,117	-9,599,987
9	Investment Tax Credit Adjustment (Net)	1,142,301	326,869
10	Net (Increase) Decrease in Receivables	-12,548,004	3,814,073
11	Net (Increase) Decrease in Inventory	-6,285,284	-12,306,638
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-7,717,708	-24,376,845
14	Net (Increase) Decrease in Other Regulatory Assets	-105,234,939	40,201,156
15	Net Increase (Decrease) in Other Regulatory Liabilities	-22,854,309	-57,333,724
16	(Less) Allowance for Other Funds Used During Construction	5,995,175	6,092,152
17	(Less) Undistributed Earnings from Subsidiary Companies	4,022,911	9,648,253
18	Other (provide details in footnote):	29,227,514	9,988,840
19			
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	85,170,165	134,366,446
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-279,621,563	-217,813,466
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	7,597,141	4,026,460
31	Other (provide details in footnote): Sale of Emiossion Allowance	19,845,542	11,322,948
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-267,373,162	-210,516,978
35			
36	Acquisition of Other Noncurrent Assets (d)		-89,507
37	Proceeds from Disposal of Noncurrent Assets (d)	525,994	34,919
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies	-12,373,146	
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)	-24,348,700	-17,978,726
45	Proceeds from Sales of Investment Securities (a)	26,110,459	20,777,593

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables	-789,874	
50	Net (Increase) Decrease in Inventory		551,536
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
54	Refundable deposit for tax related liabilities	-43,926,946	
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-322,175,375	-207,221,163
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	240,000,000	116,300,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)	84,385,000	32,944,405
67	Other (provide details in footnote):		
68	Capital Infusion	51,000,000	47,049,883
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	375,385,000	196,294,288
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-81,063,636	-116,300,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):	-883,004	-2,939,991
77			
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-53,490,283	-51,109,346
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	239,948,077	25,944,951
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	2,942,867	-46,909,766
87			
88	Cash and Cash Equivalents at Beginning of Period	2,404,300	49,314,066
89			
90	Cash and Cash Equivalents at End of period	5,347,167	2,404,300

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

Plant	$ 8,073,030
Regulatory Assets	3,715,904
Unamortized Debt expense	(565,131)
Unamortized discount	234,527
Water Rights	1,042,008

Total	$12,500,338

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

Non-Cash Pension expense	$ 6,868,159
Unbilled Revenue	(4,949,163)
Gain on Sale of Assets	(4,268,101)
Gain on Sale of Utility	(321,364)
Other Current Liabilities	15,750,577
Other Long-term Assets	2,147,078
Other Long-Term Liabilities	14,000,328

Total	$29,227,514

Schedule Page: 120 Line No.: 76 Column: b

Other Long-term assets	$ (336,404)
Other Long-term liabilities	(546,600)

Total	$ (883,004)

NOTES TO FINANCIAL STATEMENTS

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

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SEE PAGE 123 FOR REQUIRED INFORMATION.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

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

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

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

Regulation of Utility Operations
IPC follows SFAS 71, *"Accounting for the Effects of Certain Types of Regulation,"* and its financial statements reflect the effects of the different rate-making principles followed by the jurisdictions regulating IPC. The application of SFAS 71 by IPC can result in IPC recording expenses in a period different than the period the expense would be recorded by an unregulated enterprise. When this occurs, costs are deferred as regulatory assets on the balance sheet and recorded as expenses in the periods when those same amounts are reflected 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.

IPC has a Power Cost Adjustment (PCA) mechanism that provides for annual adjustments to the rates charged to its Idaho retail customers. These adjustments are based on forecasts of net power supply costs, which are fuel and purchased power less off-system sales, and the true-up of the prior year's forecast. During the year, approximately 90 percent of the difference between the actual and forecasted costs is deferred with interest. The ending balance of this deferral, called the true-up for the current year's portion and the true-up of the true-up for the prior years' unrecovered or over-recovered portion, is then included in the calculation of the next year's PCA.

The effects of applying SFAS 71 are discussed in more detail in Note 6 - "Regulatory Matters."

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

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

Property, Plant and Equipment and Depreciation
The cost of utility plant in service represents the original cost of contracted services, direct labor and material, Allowance for Funds Used During Construction (AFDC) and indirect charges for engineering, supervision and similar overhead items. Maintenance and repairs of property and replacements and renewals of items determined to be less than units of property are expensed to operations. Repair and maintenance costs associated with planned major maintenance are recorded as these costs are incurred. 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 2.95 percent in 2007 and 2.75 percent in 2006.

Long-lived assets are periodically reviewed for impairment when events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable as prescribed under SFAS 144. SFAS 144 requires that if the sum of the undiscounted expected future cash flows from an asset is less than the carrying value of the asset, an impairment must be recognized in the financial statements.

Allowance for Funds Used During Construction

AFDC represents the cost of financing construction projects with borrowed funds and equity funds. While cash is not realized currently from such allowance, it is realized under the rate-making process over the service life of the related property through increased revenues resulting from a higher rate base and higher depreciation expense. The component of AFDC attributable to borrowed funds is included as a reduction to interest expense, while the equity component is included in other income. IPC's weighted-average monthly AFDC rates for 2007 and 2006 were 6.8 percent and 7.6 percent respectively. IPC's reductions to interest expense for AFDC were $8 million for 2007 and $4 million for 2006. Other income included $6 million and $6 million of AFDC for 2007and 2006, respectively.

Revenues

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

Income Taxes

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

Consistent with orders and directives of the Idaho Public Utilities Commission (IPUC), the regulatory authority having principal jurisdiction, IPC's deferred income taxes (commonly referred to as normalized accounting) are provided for the difference between income tax depreciation and straight-line depreciation computed using book lives on coal-fired generation facilities and properties acquired after 1980. On other facilities, deferred income taxes are provided for the difference between accelerated income tax depreciation and straight-line depreciation using tax guideline lives on assets acquired prior to 1981. Deferred income taxes are not provided for those income tax timing differences where the prescribed regulatory accounting methods do not provide for current recovery in rates. Regulated enterprises are required to recognize such adjustments as regulatory assets or liabilities if it is probable that such amounts will be recovered from or returned to customers in future rates. See Note 2 for more information.

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.

Stock-Based Compensation

Effective January 1, 2006, IPC adopted SFAS No. 123 (revised 2004), *"Share-Based Payment"* (SFAS 123(R)) using the modified prospective application method. SFAS 123(R) changes measurement, timing and disclosure rules relating to share-based payments, requiring that the fair value of all share-based payments be expensed. The adoption of SFAS 123(R) did not have a material impact on IPC's financial statements for the year ended December 31, 2006.

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. The following table presents IPC's accumulated other comprehensive loss balance at December 31 (net of tax):

	2007	2006
	(thousands of dollars)	
Unrealized holding gains on available-for-sale securities	$ 568	$ 1,311
Deferred compensation plan	(6,724)	(7,048)
Total	$ (6,156)	$ (5,737)

Other Accounting Policies

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

Reclassifications

Certain items previously reported for years prior to 2007 have been reclassified to conform to the current year's presentation. Net income and shareholders' equity were not affected by these reclassifications.

New Accounting Pronouncements

SFAS 157: In September 2006, the FASB issued SFAS 157, *"Fair Value Measurements."* SFAS 157 defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles, and expands disclosures about fair value measurements. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. IPC adopted SFAS 157 on January 1, 2008, and IPC does not expect SFAS 157 to have a material impact on its financial statements.

SFAS 159: In February 2007, the FASB issued SFAS No. 159, *"The Fair Value Option for Financial Assets and Financial Liabilities - Including an Amendment of FASB Statement No. 115"* (SFAS 159). This standard permits an entity to choose to measure many financial instruments and certain other items at fair value. Most of the provisions in SFAS 159 are elective; however, the amendment to SFAS No. 115, *"Accounting for Certain Investments in Debt and Equity Securities,"* applies to all entities with available-for-sale and trading securities. The fair value option established by SFAS 159 permits all entities to choose to measure eligible items at fair value at specified election dates. A business entity will report unrealized gains and losses on items for which the fair value option has been elected in earnings at each subsequent reporting date. The fair value option: (a) may be applied instrument by instrument, with a few exceptions, such as investments otherwise accounted for by the equity method; (b) is irrevocable (unless a new election date occurs); and (c) is applied only to entire instruments and not to portions of instruments. SFAS 159 is effective as of the beginning of an entity's first fiscal year that begins after November 15, 2007. IPC adopted SFAS 159 on January 1, 2008 and did not elect the fair value option for any existing eligible items. However, IPC will continue to evaluate items on a case-by-case basis for consideration of the fair value option.

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

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

FSP FIN 39-1: In April 2007 the FASB issued FASB Staff Position No. FIN 39-1 (FSP FIN 39-1), "*Amendment of FASB Interpretation No. 39*" (FIN 39). FSP FIN 39-1 modifies FIN 39, "*Offsetting of Amounts Related to Certain Contracts*," and permits reporting entities to offset receivables or payables recognized upon payment or receipt of cash collateral against fair value amounts recognized for derivative instruments that have been offset under a master netting arrangement. FSP FIN 39-1 requires disclosure of a reporting entity's accounting policy (to offset or not offset) as well as amounts recognized for the right to reclaim cash collateral, or the obligation to return cash collateral, that have been offset against net derivative positions. FSP FIN 39-1 is effective for fiscal years beginning after November 15, 2007. IPC adopted FSP FIN 39-1 on January 1, 2008 and its adoption did not have a material impact on its financial statements.

EITF Issue No. 06-11: In June 2007, the FASB ratified Emerging Issues Task Force Issue No. 06-11, "*Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards*" (EITF 06-11), which requires income tax benefits from dividends or dividend equivalents that are charged to retained earnings and are paid to employees for equity classified awards and outstanding equity share options to be recognized as an increase in additional paid-in capital and to be included in the pool of excess tax benefits available to absorb potential future tax deficiencies on share-based payment awards. EITF 06-11 became effective on January 1, 2008. The adoption of EITF 06-11 is not expected to have a material impact on IPC's financial statements.

2. INCOME TAXES:

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

	2007	2006
	(thousands of dollars)	
Deferred tax assets:		
Regulatory liability	$ 42,968	$ 41,825
Advances for construction	10,172	9,212
Deferred compensation	16,423	14,381
Emission allowances	6,921	12,175
Partnership Investments	572	308
Retirement benefits	20,753	26,392
Other	8,810	13,154
Total	106,619	117,447
Deferred tax liabilities:		
Property, plant and equipment	227,337	230,361
Regulatory asset	308,290	343,590
Conservation programs	3,169	4,437
PCA	45,008	8,384
Retirement benefits	6,945	18,055
Other	564	1,871
Total	591,313	606,698
Net deferred tax liabilities	$ 484,694	$ 489,251

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

	2007	2006
	(thousands of dollars)	
Computed income taxes based on statutory federal income tax rate	$ 38,947	$ 48,408
Change in taxes resulting from:		
Equity earnings of subsidiary companies	(1,408)	(3,377)
AFDC	(4,757)	(3,542)

Capitalized Interest	2,289	1,394
Investment tax credits	(3,578)	(3,513)
Repair allowance	(2,450)	(2,450)
Removal Cost	(3,787)	(1,912)
Pension Accrual	1,022	1,902
Capitalized overhead costs	(4,200)	(2,940)
Tax accounting method change	0	6,122
Uncertain Tax Positions	(3,346)	0
Settlement of prior years tax returns	0	(6,199)
State income taxes, net of federal benefit	6,618	7,820
Depreciation	7,576	5,757
Other, Net	1,771	(3,091)
Total income tax expense	$ 34,697	$ 44,379
Effective tax rate	31.2 %	32.1 %

The items comprising income tax expense are as follows:

	2007	2006
	(thousands of dollars)	
Income taxes currently payable (receivable):		
Federal	$ 7,963	$ 48,366
State	(6,202)	5,286
Total	1,761	53,652
Income taxes deferred:		
Federal	28,412	(9,960)
State	6,223	360
Total	34,635	(9,600)
Uncertain Tax Positions:		
Federal	(3,345)	0
State	(241)	0
Total	(3,586)	0
Investment tax credits:		
Deferred	5,465	3,840
Restored	(3,578)	(3,513)
Total	1,887	327
Total income tax expense	$ 34,697	$ 44,379

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

FIN 48

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

Balance at January 1, 2007	$ 21,180
Additions for tax positions of prior years	848
Reductions for tax positions of prior years	(4,434)

Balance at December 31, 2007	$	17,594

If recognized, the $17.6 million balance of unrecognized tax benefits would affect IPC's effective tax rate.

IPC is disputing the Internal Revenue Service's (IRS) disallowance of IPC's use of the simplified service cost method (SSCM) of uniform capitalization for tax years 2001-2003. The dispute is under review with the IRS Appeals Office. In December 2007, the Appeals Office informed IDACORP that the IRS had completed their review of IPC's SSCM settlement computations. After evaluating the IRS review findings, IPC adjusted its measurement for the SSCM uncertain tax position which resulted in a $4.4 million reduction of the accrued liability for this item. IDACORP expects that the appeals process and the U.S. Congress Joint Committee on Taxation review process will be completed during 2008. The expected resolution would result in a decrease to IPC's unrecognized tax benefits of $13.6 million.

IPC recognizes interest accrued related to unrecognized tax benefits as interest expense and penalties as other expense. FIN 48 allows companies to change their accounting policy election for interest and penalties upon adoption of the standard. IPC had classified interest as income taxes prior to the adoption of FIN 48. IPC's 2007 interest expense includes a $1 million net reduction for interest related to unrecognized tax benefits. The reduction was due primarily to the decrease in IPC's interest accrual for the SSCM uncertain tax position. As of December 31, 2007, IPC had accrued interest of $5.5 million. No penalties are accrued.

IPC is subject to examination by its major tax jurisdictions – U.S. federal and state of Idaho – for tax years 2004 through 2006. The IRS began its examination of these years in November 2007. IPC is unable to predict the outcome of this examination.

3. COMMON STOCK AND STOCK-BASED COMPENSATION:

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

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

IPC Common Stock

In 2007 and 2006, IDACORP contributed $51 million and $47 million, respectively, of additional equity to IPC. No additional shares of IPC common stock were issued.

Stock-Based Compensation

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

The LTICP for officers, key employees and directors permits the grant of nonqualified stock options, incentive stock options, stock appreciation rights, restricted stock, restricted stock units, performance units, performance shares and other awards. The RSP permits only the grant of restricted stock or performance-based restricted stock. At December 31, 2007, the maximum number of IDACORP shares available under the LTICP and RSP were 1,611,355 and 108,595, respectively.

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

	2007	2006
Compensation cost	$ 2,473	$ 1,458
Income tax benefit	$ 967	$ 570

No equity compensation costs have been capitalized.

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

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

The performance goals for the 2007 awards are independent of each other and equally weighted, and are based on two metrics, cumulative earnings per share (CEPS) and total shareholder return (TSR) relative to a peer group. The fair value of the CEPS portion is based on the market value at the date of grant, reduced by the loss in time-value of the estimated future dividend payments, using an expected quarterly dividend of $0.30. The fair value of the TSR portion is estimated using a statistical model that incorporates the probability of meeting performance targets based on historical returns relative to the peer group. Both performance goals are measured over the three-year vesting period and are charged to compensation expense over the vesting period based on the number of shares expected to vest.

A summary of restricted stock and performance share activity is presented below.

	Number of Shares	Weighted-Average Grant Date Fair Value
Nonvested shares at December 31, 2006	184,296	$ 28.32
Shares granted	88,519	28.94
Shares forfeited	(4,764)	31.09
Shares vested	(24,555)	31.16
Nonvested shares at December 31, 2007	243,496	$ 28.20

The total fair value of shares vested during the years ended December 31, 2007 and 2006 was $0.9 million and $0.6 million, respectively. At December 31, 2007, IPC had $2.3 million of total unrecognized compensation cost related to nonvested share-based compensation that was expected to vest. These costs are expected to be recognized over a weighted-average period of 1.64 years. IPC uses IDACORP original issue and/or treasury shares for these awards.

Stock options: Stock option awards are granted with exercise prices equal to the market value of the stock on the date of grant. The options have a term of 10 years from the grant date and vest over a five-year period. Upon adoption of SFAS 123(R) on January 1, 2006, the fair value of each option is amortized into compensation expense using graded-vesting. Beginning in 2006, stock options are not a significant component of share-based compensation awards under the LTICP.

The fair values of all stock option awards have been estimated as of the date of the grant by applying a binomial option pricing model. The application of this model involves assumptions that are judgmental and sensitive in the determination of compensation expense. The following key assumptions were used in determining the fair value of options granted:

	2007	2006
Dividend yield, based on current dividend and stock price on grant date	-	3.7%
Expected stock price volatility, based on IDACORP historical volatility	-	18%
Risk-free interest rate based on U.S. Treasury composite rate	-	4.92%

Expected term based on the SEC "simplified" method	-	6.50 years

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

	2007	2006
Weighted-average grant-date fair value	$ -	$ -
Fair value of options vested	579	1,275
Intrinsic value of options exercised	11	2,883
Cash received from exercises	40	9,614
Tax benefits realized from exercises	4	1,127

As of December 31, 2007, there was $0.1 million of total unrecognized compensation cost related to stock options. These costs are expected to be recognized over a weighted average period of 0.8 years. IPC uses IDACORP original issue and/or treasury shares to satisfy exercised options.

IPC's transactions in IDACORP stock are summarized below.

	Number of Shares	Weighted-Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value (000s)
Outstanding at December 31, 2006	619,091	$ 33.84	5.71	$ 3,385
Exercised	(1,412)	28.37		
Forfeited	(1,636)	28.44		
Expired	(4,800)	39.91		
Outstanding at December 31, 2007	611,243	$ 33.75	4.71	$ 2,310
Vested or expected to vest at December 31, 2007	600,362	$ 33.85	4.68	$ 2,234
Exercisable at December 31, 2007	490,139	$ 35.12	4.31	$ 1,459

4. LONG-TERM DEBT

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

	2007	2006
	(thousands of dollars)	
First mortgage bonds:		
7.38% Series due 2007	$ -	$ 80,000
7.20% Series due 2009	80,000	80,000
6.60% Series due 2011	120,000	120,000
4.75% Series due 2012	100,000	100,000
4.25% Series due 2013	70,000	70,000
6% 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	-

6.25% Series due 2037	100,000	-
Total first mortgage bonds	945,000	785,000
Pollution control revenue bonds:		
Variable Auction Rate Series 2003 due 2024 (a)	49,800	49,800
Variable Auction Rate Series 2006 due 2026 (a)	116,300	116,300
Variable Rate Series 2000 due 2027	4,360	4,360
Total pollution control revenue bonds	170,460	170,460
American Falls bond guarantee	19,885	19,885
Milner Dam note guarantee	10,636	11,700
Unamortized premium (discount) - net	(3,409)	(3,097)
Total long-term debt	$ 1,142,572	$ 983,948

(a) 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, 2007, to $1.111 billion.

At December 31, 2007, the maturities for the aggregate amount of long-term debt outstanding were (in thousands of dollars):

2008	2009	2010	2011	2012	Thereafter
$ 1,064	$ 81,064	$ 1,064	$ 121,064	$ 101,064	$ 840,661

At December 31, 2007 and 2006, the overall effective cost of IPC's outstanding debt was 5.72 percent and 5.71 percent, respectively.

On June 22, 2007, IPC issued $140 million of its 6.30% First Mortgage Bonds, Secured Medium-Term Notes, Series F, due June 15, 2037. IPC used the net proceeds to pay down outstanding commercial paper, which had increased to $164 million in June 2007 because of increased capital expenditures.

On October 18, 2007, IPC issued $100 million of its 6.25% First Mortgage Bonds, Secured Medium-Term Notes, Series G, due October 15, 2037. IPC used the net proceeds to retire $80 million of 7.38% First Mortgage Bonds due December 1, 2007, and paid down outstanding commercial paper.

On October 3, 2006, IPC completed a tax-exempt bond financing in which Sweetwater County, Wyoming issued and sold $116.3 million aggregate principal amount of its Pollution Control Revenue Refunding Bonds Series 2006. The bonds will mature on July 15, 2026. The $116.3 million proceeds were loaned by Sweetwater County to IPC pursuant to a loan agreement, dated as of October 1, 2006, between Sweetwater County and IPC. On October 10, 2006, the proceeds of the new bonds, together with certain other moneys of IPC, were used to refund Sweetwater County's Pollution Control Revenue Refunding Bonds Series 1996A, Series 1996B and Series 1996C totaling $116.3 million. The regularly scheduled principal and interest payments on the Series 2006 bonds, and principal and interest payments on the bonds upon mandatory redemption on determination of taxability, are insured by a financial guaranty insurance policy issued by Ambac Assurance Corporation. IPC and Ambac entered into an Insurance Agreement, dated as of October 3, 2006, pursuant to which IPC has agreed, among other things, to pay certain premiums to Ambac and to reimburse Ambac for any payments made under the policy. To secure its obligation to make principal and interest payments on the loan made to IPC, IPC issued and delivered to a trustee IPC's First Mortgage Bonds, Pollution Control Series C, in a principal amount equal to the amount of the new bonds. The Humboldt County series 2003 $49.8 million bonds have a similar financial guaranty insurance policy from Ambac.

On January 18, 2008, Fitch Ratings, Inc. announced that it had downgraded Ambac's insurer financial strength rating to "AA" from "AAA" and was keeping the rating on negative watch. Fitch also downgraded the Humboldt bonds and Sweetwater bonds to "AA" from "AAA." S&P and Moody's ratings for the bonds remain unchanged. However, Moody's placed Ambac's insurance financial strength rating on review for possible downgrade on January 16, 2008 and, as a result of this review, Moody's-rated securities that are guaranteed by Ambac were also placed under review for possible downgrade, except those with higher public underlying ratings. S&P also placed Ambac's financial strength, financial enhancement and issuer credit ratings on CreditWatch with negative implications on

January 18, 2008. On February 25, 2008, S&P affirmed Ambac's "AAA" financial strength and financial enhancement ratings, but retained the negative watch.

The maximum interest rate is 14 percent for the Sweetwater bonds and at specified rates capped at 12 percent for the Humboldt bonds. On February 27, 2008, auctions were held for both series of pollution control bonds. The Sweetwater bonds had a successful auction establishing a new interest rate of 7.95 percent. The Humboldt bonds experienced a "failed auction" which resulted in a new interest rate of 5.464 percent (currently based on LIBOR multiplied by 1.75) and the Humboldt bonds continuing to be held by the current holders.

Long-Term Financing

IPC has in place a registration statement that can be used for the issuance of an aggregate principal amount of $350 million of first mortgage bonds (including medium-term notes) and unsecured debt.

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

As of December 31, 2007, IPC could issue under the mortgage approximately $535 million of additional first mortgage bonds based on unfunded property additions and $532 million of additional first mortgage bonds based on retired first mortgage bonds. At December 31, 2007, unfunded property additions were approximately $900 million.

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

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

5. NOTES PAYABLE:

IPC has a $300 million credit facility 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, 2007, IPC had regulatory authority to incur up to $450 million of short-term indebtedness. Balances and interest rates of IPC's short-term borrowings were as follows at December 31 (in thousands of dollars):

	2007	2006
	(thousand of dollars)	
Balances:		
At the end of year	$ 136,585	$ 52,200
Average during the year	$ 96,890	$ 14,211
Weighted-average interest rate:		

At the end of year	5.56%	5.50%
Average during the year	5.54%	5.50%

6. REGULATORY MATTERS:

Regulatory Assets and Liabilities

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

	As of December 31, 2007					
Description	Remaining Amortization Period	Earning a Return	Not Earning a Return	Pending Regulatory Treatment	2007 Total	Total as of December 31, 2006
Regulatory Assets:						
Income Taxes		$ -	$ 309,902	$ -	$ 309,902	$ 343,590
Benefit Plans (1)		-	17,765	-	17,765	46,181
Deferred Pension Costs (1)		-	2,797	-	2,797	-
Conservation	2010	8,107	-	-	8,107	11,349
PCA Deferral	2008	92,323	-	-	92,323	-
Oregon Deferral (2)		5,100	-	-	5,100	9,559
Asset Retirement Obligations (3)		-	12,188	-	12,188	11,206
Grid West Loans		60	746	302	1,108	1,290
Other	Through 2010	121	429	-	550	1,853
Total (4)		$ 105,711	$ 343,827	$ 302	$ 449,840	$ 425,028
Regulatory Liabilities:						
Income Taxes		$ -	$ 44,580	$ -	$ 44,580	$ 41,825
Conservation	2008	1,893	-	-	1,893	6,328
PCA Accrual		-	-	-	-	15,173
FCA Deferral		-	2,145	-	2,145	-
Asset Retirement Obligations (3)		-	155,314	-	155,314	156,162
Deferred ITC		-	71,001	-	71,001	69,114
BPA Settlement	2008	851	-	-	851	2,124
Emission Allowance		-	-	-	-	4,118
Other		-	586	-	586	-
Total (5)		$ 2,744	$ 273,626	$ -	$ 276,370	$ 294,844

(1) See Note 8.
(2) Capped at 10 percent increase per year.
(3) See Note 12.
(4) Includes $172 reported in other current assets on the balance sheets.
(5) Includes $2,166 reported in other current liabilities on the balance sheets.

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

General Rate Case

Idaho: On May 12, 2006, the IPUC issued an order approving a settlement of IPC's general rate case filed in October 2005. The order approved an average increase of 3.2 percent in base rate, or $18 million in revenues, effective June 1, 2006.

Deferred (Accrued) Net Power Supply Costs

Idaho: IPC has a Power Cost Adjustment (PCA) mechanism that provides for annual adjustments to the rates charged to its Idaho retail customers. These adjustments are based on forecasts of net power supply costs, which are fuel and purchased power less off-system sales, and the true-up of the prior year's forecast. During the year, 90 percent of the difference between the actual and forecasted costs is deferred with interest. The ending balance of this deferral, called the true-up for the current year's portion and the true-up of the true-up for the prior years' unrecovered portion, is then included in the calculation of the next year's PCA.

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

On June 1, 2006, IPC implemented the 2006-2007 PCA, which reduced the PCA component of customers' rates from the then-existing level, which was recovering $76.7 million above then-existing base rates, to a level that was $46.8 million below those base rates, a decrease of approximately $123.5 million.

Idaho Load Growth Adjustment Rate (LGAR): On January 9, 2007, the IPUC issued an order resetting IPC's LGAR to $29.41 per MWh, effective April 1, 2007. The LGAR subtracts the cost of serving additional Idaho retail load from the net power supply costs IPC is allowed to include in its PCA. The order revised the LGAR from the original rate of $16.84 per MWh set when the PCA began in 1993. This amount was established as the projected additional variable energy costs attributable to load growth and was subtracted from each year's PCA expense. In its petition, IPC had requested the use of the embedded cost of serving new load and a rate of $6.81 per MWh, but the IPUC in its order determined to use the projected marginal cost, which resulted in a higher LGAR.

Emission Allowances: During 2007, IPC sold 35,000 SO_2 emission allowances for a total of $19.6 million, after subtracting transaction fees. The sales proceeds to be allocated to the Idaho jurisdiction are approximately $18.5 million ($11.3 million net of tax, assuming a tax rate of approximately 39 percent). On January 15, 2008, a workshop was held to discuss whether the customer share of the Idaho jurisdictional portion of the 2007 sales proceeds should once again be included as a PCA credit or used to reduce investment costs in wind development, green tags, or other options that would provide longer term customer benefits. Because the workshop participants were unable to reach a consensus regarding the use of the SO_2 emission allowance proceeds, the IPUC determined that the case would proceed under modified procedure. Written comments were due February 25, 2008.

In 2005 and early 2006, IPC sold 78,000 SO_2 emission allowances for a total of $81.6 million, after subtracting transaction fees. The sales proceeds to be allocated to the Idaho jurisdiction are approximately $76.8 million ($46.8 million net of tax, assuming a tax rate of approximately 39 percent). On May 12, 2006, the IPUC approved a stipulation that allowed IPC to retain ten percent as a shareholder benefit with the remaining 90 percent plus a carrying charge recorded as a customer benefit. This customer benefit is included in IPC's PCA calculations as a credit to the PCA true-up balance and is currently reflected in PCA rates during the June 1, 2007 through May 31, 2008 PCA rate year.

Oregon: On April 30, 2007, IPC filed for an accounting order with the OPUC to defer net power supply costs for the period of May 1, 2007, through April 30, 2008, in anticipation of higher than "normal" power supply expenses. In the Oregon general rate case, "normal" power supply expenses were set at a negative number (meaning that under normal water conditions IPC should be able to sell enough surplus energy to pay for all fuel and purchased power expenses and still have revenue left over to offset other costs). IPC requested authorization to defer an estimated $5.7 million, which is Oregon's jurisdictional share of the excess power supply costs. IPC also requested that it earn its Oregon authorized rate of return on the deferred balance and recover the amount through rates in future years, as approved by the OPUC. IPC is awaiting an order from the OPUC.

On April 28, 2006, IPC filed for an accounting order with the OPUC to defer net power supply costs for the period of May 1, 2006, through April 30, 2007. IPC requested authorization to defer an estimated $3.3 million, which is Oregon's jurisdictional share of the excess power supply costs. IPC also requested that it earn its Oregon authorized rate of return on the deferred balance and recover the amount through rates in future years, as approved by the OPUC. On April 25, 2007, a tentative settlement agreement was reached on the deferral application with the OPUC Staff and the Citizens' Utility Board in the amount of $2 million. The parties also agreed that IPC would file an application for an Oregon PCA mechanism. The settlement stipulation was approved by the OPUC on December 13, 2007.

The timing of recovery of Oregon power supply cost deferrals is subject to an Oregon statute that specifically limits rate amortizations of deferred costs to six percent per year. IPC is currently amortizing through rates power supply costs associated with the western energy situation of 2001. Full recovery of the 2001 deferral is not expected until 2009. The 2006-2007 and the 2007-2008 deferrals would have to be amortized sequentially following the full recovery of the 2001 deferral.

IPC's deferred (accrued) net power supply costs consisted of the following at December 31 (in thousands of dollars):

	2007	2006
Idaho PCA current year:		
Accrual for the 2007-2008 rate year (1)	$ -	$ (3,484)
Deferral for the 2008-2009 rate year (2)	85,732	-
Idaho PCA true-up awaiting recovery (refund):		
Authorized May 2006	-	(11,689)
Authorized May 2007	6,591	-
Oregon deferral:		
2001 costs	2,993	6,670
2005 costs	-	2,889
2006 costs	2,107	-
Total deferral (accrual)	$ 97,423	$ (5,614)

(1) The 2007-2008 PCA adjustment included $69 million of emission allowance sales to be credited to customers.
(2) The 2008-2009 PCA deferral balance includes $17 million of emission allowance sales in 2007.

Fixed Cost Adjustment Mechanism (FCA)
On January 27, 2006, IPC filed with the IPUC for authority to implement a rate adjustment mechanism that would adjust rates downward or upward to recover fixed costs independent of the volume of IPC's energy sales. This filing was a continuation of a 2004 case that was opened to investigate the financial disincentives to investment in energy efficiency by IPC. This true-up mechanism would be applicable only to residential and small general service customers. The accounting for the FCA will be separate from the PCA. IPC proposed a three percent cap on any rate increase to be applied at the discretion of the IPUC.

IPC and the IPUC Staff agreed in concept to a three-year pilot program beginning January 1, 2007, and a stipulation was filed on December 18, 2006. The stipulation called for the implementation of a FCA mechanism pilot program as proposed by IPC in its original application with additional conditions and provisions related to customer count and weather normalization methodology, recording of the FCA deferral amount in reports to the IPUC and detailed reporting of demand side management (DSM) activities. The IPUC approved the stipulation on March 12, 2007. The pilot program began retroactively on January 1, 2007, and will run through 2009, with the first rate adjustment to occur on June 1, 2008, and subsequent rate adjustments to occur on June 1 of each year thereafter during the term of the pilot program. IPC accrued $2.1 million of FCA expense in 2007.

Open Access Transmission Tariff (OATT)
On March 24, 2006, IPC submitted a revised OATT filing with the FERC requesting an increase in transmission rates. In the filing IPC proposed to move from a fixed rate to a formula rate, which allows for transmission rates to be updated each year based on FERC Form 1 data. The formula rate request included a rate of return on equity of 11.25 percent. The proposed rates would have produced an annual revenue increase for the FERC jurisdiction of approximately $13 million based on 2004 test year data. The FERC accepted IPC's rates, effective June 1, 2006, subject to adjustment to conform to SFAS 109 tax accounting requirements, which lowered the estimated annual increase in revenues to approximately $11 million.

On August 8, 2007, the FERC approved a settlement agreement filed in June 2007 by the parties on all issues except the treatment of contracts for transmission service that contain their own terms, conditions and rates and that were in existence before the implementation of OATT in 1996 (Legacy Agreements). The effect of this settlement was to reduce the estimated FERC jurisdictional annual revenue increase from $11 million to approximately $8.2 million based on 2004 test year data. The settlement agreement required that amounts collected in excess of the new rates for the June 1, 2006 through July 31, 2007 period be refunded with interest to customers. These refunds totaled approximately $1.7 million and were paid in August 2007.

Hearings were held before the FERC in June 2007 regarding the treatment of the Legacy Agreements. IPC's position was that the revenue IPC receives under the Legacy Agreements should be credited against the total transmission revenue requirement attributed to OATT customers and that the contract demands of the Legacy Agreements should not be included in the load divisor of the rate formula. The intervenors in the proceeding took the position that such contract demands should be included in the load divisor, rather than being revenue credited.

On August 31, 2007, the FERC Presiding Administrative Law Judge (ALJ) issued an initial decision (Initial Decision) with respect to the treatment of the Legacy Agreements, which is on file and publicly available at FERC Docket No. ER06-787. In the Initial Decision, the ALJ concluded that (i) the Legacy Agreements should be included in the load divisor of the rate formula and (ii) the revenue IPC receives under the Legacy Agreements should not be credited against the total transmission revenue requirement attributed to OATT customers. If the Initial Decision is implemented, IPC estimates that this ruling will reduce the estimated FERC jurisdictional annual revenue increase (based on 2004 test year data) to $6.8 million.

IPC has appealed the Initial Decision to the FERC. However, if the Initial Decision is implemented, IPC would make additional refunds, including interest, of approximately $2.4 million for the June 1, 2006 through December 31, 2007 period. IPC has reserved this entire amount. IPC expects to pursue recovery of amounts not received pursuant to a final order in this proceeding through additional proceedings at the FERC or through the state ratemaking process. IPC is awaiting a final FERC order.

Pension Expense

In the 2003 Idaho general rate case, the IPUC disallowed recovery of pension expense because there were no current contributions being made to the plan. On March 20, 2007, IPC filed a request with the IPUC to clarify that IPC can consider future contributions made to the pension plan a recoverable cost of service. An order approving this application would not determine the methodology of recovery but would permit IPC to record a regulatory asset related to pension costs. On June 1, 2007, the IPUC issued its order authorizing IPC to account for its defined benefit pension expense on a cash basis, and to defer and account for accrued pension expense under SFAS 87, *"Employers' Accounting for Pensions,"* as a regulatory asset. The IPUC acknowledged that it is appropriate for IPC to seek recovery in its revenue requirement of reasonable and prudently incurred pension expense based on actual cash contributions. IPC will begin deferring pension expense to a regulatory asset account to be matched with revenue when future pension contributions are recovered through rates. The deferral of pension expense did not begin until $4.1 million of past contributions still recorded on the balance sheet at December 31, 2006, were expensed. For 2007, approximately $2.8 million was deferred to a regulatory asset beginning in the third quarter. IPC did not request a carrying charge to be applied to the deferral of the accrued SFAS 87 expense.

7. COMMITMENTS AND CONTINGENCIES:

Purchase Obligations:

As of December 31, 2007, IPC had agreements to purchase energy from 94 cogeneration and small power production (CSPP) facilities with contracts ranging from one to 30 years. Under these contracts IPC is required to purchase all of the output from the facilities inside the IPC service territory. For projects outside the IPC service territory, IPC is required to purchase the output that it has the ability to receive at the facility's requested point of delivery on the IPC system. IPC purchased 777,147 megawatt-hours (MWh) at a cost of $45 million in 2007and 911,132 MWh at a cost of $54 million in 2006.

At December 31, 2007, IPC had the following long-term commitments relating to purchases of energy, capacity, transmission rights and fuel:

	2008	2009	2010	2011	2012	Thereafter
			(thousands of dollars)			
Cogeneration and small power production	$ 75,813	$ 99,246	$ 99,246	$ 103,435	$ 103,435	$ 1,511,405
Power and transmission rights	37,884	4,971	4,971	2,619	2,619	11,433
Fuel	54,290	44,465	24,478	25,214	6,636	54,466

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

	2008	2009	2010	2011	2012	Thereafter
			(thousands of dollars)			
Operating leases	$ 2,568	$ 3,336	$ 3,336	$ 1,368	$ 1,368	$ 5,719
Maintenance and service agreements	49,777	4,006	4,006	804	804	3,584
FERC and other industry related fees	4,133	3,990	3,990	3,884	3,884	19,493

Guarantees
IPC has agreed to guarantee the performance of reclamation activities at Bridger Coal Company of which Idaho Energy Resources Co., a subsidiary of IPC, owns a one-third interest. This guarantee, which is renewed each December, was $60 million at December 31, 2007. Bridger Coal Company has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. Bridger Coal Company and IPC expect that the fund will be sufficient to cover all such costs. Because of the existence of the fund, the estimated fair value of this guarantee is minimal.

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

Wah Chang: On May 5, 2004, Wah Chang, a division of TDY Industries, Inc., filed two lawsuits in the U.S. District Court for the District of Oregon against numerous defendants. IDACORP, IE and IPC are named as defendants in one of the lawsuits. The complaints allege violations of federal antitrust laws, violations of the Racketeer Influenced and Corrupt Organizations Act, violations of Oregon antitrust laws and wrongful interference with contracts. Wah Chang's complaint is based on allegations relating to the western energy situation. These allegations include bid rigging, falsely creating congestion and misrepresenting the source and destination of energy. The plaintiff seeks compensatory damages of $30 million and treble damages.

On September 8, 2004, this case was transferred and consolidated with other similar cases currently pending before the Honorable Robert H. Whaley sitting by designation in the U.S. District Court for the Southern District of California. The companies' filed a motion to dismiss the complaint which the court granted on February 11, 2005. Wah Chang appealed the dismissal to the U.S. Court of Appeals for the Ninth Circuit on March 10, 2005. On November 20, 2007, the Ninth Circuit affirmed the dismissal. On December 10, 2007, Wah Chang filed Petitions for Rehearing and Rehearing En Banc with the U.S. Court of Appeals for the Ninth Circuit (Ninth Circuit), which were denied on January 15, 2008. If Wah Chang decides to seek Supreme Court review, time for filing its petition for certiorari will expire on April 14, 2008. The companies cannot predict whether Wah Chang will seek certiorari or whether the Supreme Court will grant it. The companies intend to vigorously defend their position in this proceeding and believe this matter will not have a material adverse effect on their consolidated financial positions, results of operations, or cash flows.

Western Energy Proceedings at the FERC:
<u>California Power Exchange Chargeback:</u>
As a component of IPC's non-utility energy trading in the state of California, IPC entered into a participation agreement in January 1999 with the California Power Exchange (CalPX), a California non-profit public benefit corporation which at the time operated a wholesale electricity market in California. Under the participation agreement, if a participant in the CalPX defaulted on a payment, the other participants were required to pay an allocated share of the default amount to the CalPX based upon the level of trading activity of each participant during the preceding three-month period.

On January 18, 2001, the CalPX sent IPC a "default share invoice" for $2 million as a result of a Southern California Edison payment default of $215 million for power purchases. IPC made this payment. On January 24, 2001, IPC terminated its participation agreement with the CalPX. On February 8, 2001, the CalPX sent a further invoice for $5 million as a result of alleged payment defaults by Southern California Edison, Pacific Gas and Electric Company and others. However, because the CalPX owed IPC more than the claimed amount for power sold to the CalPX in November and December 2000, IPC did not pay the February 8 invoice. IPC essentially discontinued energy trading with the CalPX and the California Independent System Operator (Cal ISO) in December 2000.

A preliminary injunction was granted by a federal judge in the U.S. District Court for the Central District of California enjoining the CalPX from declaring any CalPX participant in default under the terms of the CalPX Tariff. On March 9, 2001, the CalPX filed for Chapter 11 protection with the U.S. Bankruptcy Court, Central District of California.

In April 2001, Pacific Gas and Electric Company filed for bankruptcy. The CalPX and the Cal ISO were among the creditors of Pacific Gas and Electric Company.

The FERC issued an order on April 6, 2001 requiring the CalPX to rescind all chargeback actions related to Pacific Gas and Electric Company's and Southern California Edison's liabilities but, on October 7, 2004, the FERC issued an order determining that it would not require the disbursement of chargeback funds until the completion of the California refund proceedings.

When the FERC approved a settlement of the California Refund matters among IE and the California Parties on May 22, 2006, the FERC also directed the CalPX to return the chargeback funds held by the CalPX. On June 1, 2006, IE received approximately $2.5 million from the CalPX representing the return of $2.27 million in chargeback funds plus interest.

California Refund:
In April 2001, the FERC issued an order stating that it was establishing price mitigation for sales in the California wholesale electricity market. In a June 19, 2001 order, the FERC expanded that price mitigation plan to the entire western United States electrically interconnected system. That plan included the potential for orders directing electricity sellers into California since October 2, 2000 to refund portions of their spot market sales prices if the FERC determined that those prices were not just and reasonable. After settlement discussions failed to bring resolution to the refund issues, the FERC established evidentiary hearings on July 25, 2001 to calculate refunds related to transactions in the spot markets operated by the Cal ISO and the CalPX during the period October 2, 2000, through June 20, 2001 (Refund Period).

On December 12, 2002, a FERC Administrative Law Judge issued a Certification of Proposed Findings on California Refund Liability and the FERC largely affirmed the recommendations of its Administrative Law Judge on March 26, 2003, but modified the judge's finding to enlarge refunds when it found that actual market prices paid for gas did not reliably reflect the prices that should have prevailed in competitive gas markets. The FERC also directed the Cal ISO to recalculate prices and determine the amount of "refunds" due to the organized California electricity markets. In the context of these cases, since most sellers had not been paid by the Cal ISO or the CalPX, the term "refunds" means a reduction in the amount due to sellers for power sold.

IE, along with a number of other parties, sought rehearing and judicial review of the FERC's orders.

Since that time, the Cal ISO has engaged in a detailed review of its books and records and the various adjustments the FERC has ordered to calculate "refunds." That process has taken more than four years and is not yet complete.

While those calculations were being performed, litigation before the FERC continued regarding a variety of matters that would affect the level of refunds, including among other things, cost filings, fuel cost allowance offsets, emissions offsets, cost-based recovery offsets, and allocation methods.

As the FERC issued more orders and denied rehearing, more petitions for review were filed by IE and other parties. The United States Court of Appeals for the Ninth Circuit consolidated IE's and the other parties' petitions with the petitions for review arising from earlier FERC orders in this proceeding, bringing the total number of consolidated petitions to more than two hundred. The Ninth Circuit held the appeals in abeyance pending the disposition of the market manipulation claims discussed below and the development of a comprehensive plan to brief this complicated case. The Ninth Circuit severed a subset of the stayed appeals so that briefing could commence regarding cases related to: (1) which parties are subject to the FERC's refund jurisdiction under section 201(f) of the FPA; (2) the temporal scope of refunds under section 206 of the FPA; and (3) which categories of transactions are subject to refunds.

On September 6, 2005, the Ninth Circuit issued a decision on the jurisdictional issues concluding that the FERC lacked refund authority over wholesale electric energy sales made by governmental entities and non-public utilities. On August 2, 2006, the Ninth Circuit issued its decision on the appropriate temporal reach and the type of transactions subject to the FERC refund orders and among other things (i) concluded that all transactions at issue in the case that occurred within or as a result of the CalPX and the Cal ISO were the proper subject of refund proceedings; (ii) refused to expand the refund proceedings into the bilateral markets including transactions with the California Department of Water Resources; (iii) approved the refund effective date as October 2, 2000, but also required the FERC to consider whether refunds, including possibly market-wide refunds, should be required for an earlier time due to claims that some market participants had violated governing tariff obligations (although the decision did not specify when that time would start, the California Parties generally had sought further refunds starting May 1, 2000); and (iv) effectively expanded the scope of the refund proceeding to transactions within the CalPX and Cal ISO markets outside the 24-hour spot market and energy exchange transactions.

While the refund proceedings were pending before the FERC, the California Attorney General filed a complaint with the FERC against sellers in the wholesale power market, including IE and IPC, alleging that the FERC's market-based rate requirements violate the FPA, and, even if the market-based rate requirements were valid, that the quarterly transaction reports filed by sellers did not contain the transaction-specific information mandated by the FPA and the FERC. The complaint sought refunds for an expanded time when compared to the basic refund proceeding. The FERC dismissed the complaint but on September 9, 2004, the Ninth Circuit concluded that although market-based tariffs are permissible under the FPA, the matter should be remanded to the FERC to consider whether the FERC should exercise remedial power (including some form of refunds) when a market participant failed to submit reports. On December 28, 2006, a number of sellers filed a certiorari petition to the U.S. Supreme Court. The Supreme Court declined to grant certiorari and the matter has now been remanded to the FERC.

On August 8, 2005, the FERC issued an order establishing the framework for filings by sellers who elected to make a cost showing to reduce their refund exposure. On September 14, 2005, IE and IPC made a joint cost filing, as did approximately thirty other sellers. That filing was contested by the California Parties (Pacific Gas and 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).

While the appeals of the California Attorney General's complaint were pending, and prior to the August 2, 2006 decision of the Ninth Circuit and the FERC action on the cost filing, IPC and IE reached a settlement with the California Parties that was approved by the FERC on May 22, 2006. That settlement anticipated the possibility of the outcome of the appeals discussed above and resolved the settling parties' claims in the event of the expansion of all of the refund proceedings as the Ninth Circuit ordered. Under the terms of the settlement, IE and IPC assigned $24.25 million of the rights to accounts receivable from the Cal ISO and CalPX to the California Parties to pay into an escrow account for refunds to settling parties. Amounts from that escrow not used for settling parties and $1.5 million of the remaining IE and IPC receivables that are to be retained by the CalPX are available to fund, at least partially, payment of the claims of any non-settling parties if they prevail in the remaining litigation of this matter. Any excess funds remaining at the end of the case are to be returned to IDACORP. Approximately $10.25 million of the remaining IE and IPC receivables was paid to IE and IPC under the settlement.

Although IPC and IE had reached a settlement with the California Parties, some parties representing a small portion of the total refund exposure did not join the settlement. On March 27, 2006, the FERC rejected the IE/IPC cost filing and IE and IPC sought rehearing of the rejection. By order of April 27, 2006, the FERC tolled the time for what otherwise would have been required by statute to be a decision on the request for rehearing. That request remains pending before the FERC. IE and IPC are unable to predict how or when the FERC might rule on the request for rehearing.

On June 21, 2006, the Port of Seattle, Washington filed a request for rehearing of the FERC order approving the IPC and IE/California Parties settlement. On October 5, 2006, the FERC denied the Port of Seattle's request for rehearing and on October 24, 2006, the Port of Seattle petitioned the U.S. Court of Appeals for the Ninth Circuit for review of the FERC orders approving the settlement. On October 25, 2007 the Ninth Circuit lifted the stay as to the Port of Seattle's appeal along with two other cases with which the Port of Seattle's petition remains consolidated and severed the three cases from the remainder of the consolidated cases. The Ninth Circuit established a briefing schedule which currently concludes in late June 2008 for these three cases. A date for argument has not yet been scheduled. IPC and IE are unable to predict when or how the Ninth Circuit might rule on Port of Seattle's petition for review.

Prior to December 2005, IE had accrued a reserve of $42 million for this matter. This reserve was calculated taking into account the uncertainty of collection from the CalPX and Cal ISO. In the fourth quarter of 2005, following the tentative agreement with the California Parties, IE reduced this reserve by $9.5 million to $32 million. Following payment of the $10.25 million to IE and IPC in June 2006, IE further reduced the reserve by $24.9 million to $7.1 million. This reserve was calculated taking into account several unresolved issues in the California refund proceeding.

Market Manipulation:
On March 3, 2003, the California Parties asserted that a number of wholesale power suppliers, including IE and IPC, had engaged in a variety of forms of conduct that the California Parties contended were impermissible. IE and IPC were mentioned only in limited contexts with the overwhelming majority of the claims of the California Parties relating to the conduct of other parties. On March 20, 2003, numerous parties, including IE and IPC, submitted briefs and responsive testimony.

In a March 26, 2003 order, the FERC declined to generically apply its refund determinations to sales by all market participants, although it stated that it reserved the right to provide remedies for the market against parties shown to have engaged in proscribed conduct.

On June 25, 2003, the FERC ordered over 50 entities that participated in the western wholesale power markets between January 1, 2000 and June 20, 2001, including IPC, to show cause why certain trading practices did not constitute gaming or anomalous market behavior in violation of the Cal ISO and the CalPX Tariffs. On October 16, 2003, IPC and IE reached agreement with the FERC Staff on the two orders commonly referred to as the "gaming" and "partnership" show cause orders. The FERC Staff submitted a motion to the FERC to dismiss the "partnership" proceeding because materials submitted by IPC demonstrated that IPC did not engage in impermissible partnership market behavior. The motion to dismiss the "partnership" proceeding was approved by the FERC in an order issued on January 23, 2004 and rehearing of that order was not sought within the time allowed by statute. Regarding the gaming order, the FERC Staff determined it had no basis to proceed with most of the allegations and IPC agreed to pay $83,373 to settle allegations of circular scheduling. IPC believed that it had defenses to the circular scheduling allegation but determined that the cost of settlement was less than the cost of litigation. In the settlement, IPC did not admit any wrongdoing or violation of any law. The "gaming" settlement was approved by the FERC on March 3, 2004.

Some parties have sought review of what they claim are the excessively narrow or excessively broad scope of the show cause orders, and the Ninth Circuit has consolidated those claims with the other matters and are holding them in abeyance. The Port of Seattle is the only party to appeal the orders of the FERC approving the gaming settlement and, like the dozens of other appeals pending before the Ninth Circuit, IPC is not able to predict when that appeal will be considered or the outcome of the judicial determination of these issues.

On June 25, 2003, the FERC also issued an order instituting an investigation of anomalous bidding behavior and practices in the western wholesale power markets. In this investigation, the FERC was to review evidence of alleged economic withholding of generation. The FERC determined that all bids into the CalPX and the Cal ISO markets for more than $250 per MWh for the time period May 1, 2000, through October 1, 2000, would be considered prima facie evidence of economic withholding. The FERC Staff issued data requests in this investigation to over 60 market participants including IPC. IPC responded to the FERC's data requests. In a letter dated May 12, 2004, the FERC's Office of Market Oversight and Investigations advised that it was terminating the investigation as to IPC. In March 2005, the California Attorney General, the California Public Utilities Commission, the California Electricity Oversight Board and Pacific Gas and Electric Company sought judicial review in the Ninth Circuit of the FERC's termination of this investigation as to IPC and approximately 30 other market participants. IPC has moved to intervene in these proceedings. On April 25, 2005, Pacific Gas and Electric Company sought review in the Ninth Circuit of another FERC order in the same docketed proceeding confirming the agency's earlier decision not to allow the participation of the California Parties in what the FERC characterized as its non-public investigative proceeding. Formal orders holding these cases in abeyance have expired and the Ninth Circuit has not established a briefing or decision schedule. IPC is able to predict when the Ninth Circuit will schedule briefing or decision on these cases or how it may decide them.

Pacific Northwest Refund:
On July 25, 2001, the FERC issued an order establishing another 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. A FERC Administrative Law Judge submitted recommendations and findings to the FERC on September 24, 2001 concluding that prices should be governed by the Mobile-Sierra standard of the public interest rather than the just and reasonable standard, that the Pacific Northwest spot markets were competitive and that refunds should be allowed. On December 19, 2002, the FERC reopened the proceedings to allow the submission of additional evidence related to alleged manipulation of the power market by market participants. Parties alleging market manipulation were to submit their claims to the FERC and responses were due on March 20, 2003. The Public

Utilities District No. 1 of Grays Harbor, which had executed a six-month forward contract with IPC for which performance had been completed, intervened in this FERC proceeding, asserting that its contract should be treated as a spot market contract for purposes of the FERC's consideration of refunds and requested refunds from IPC of $5 million. Grays Harbor did not suggest that there was any misconduct by IPC or IE. The companies submitted responsive testimony defending vigorously against Grays Harbor's refund claims. In addition, the Port of Seattle, the City of Tacoma and the City of Seattle made filings with the FERC on March 3, 2003, claiming that because some market participants drove prices up throughout the west through acts of manipulation, prices for contracts throughout the Pacific Northwest market should be re-set starting in May 2000 using the same factors the FERC would use for California markets. On June 25, 2003, after having considered oral argument held earlier in the month, the FERC terminated the proceeding and denied claims that refunds should be paid. The FERC denied rehearing on November 10, 2003, triggering the right to file for review. The Port of Seattle, the City of Tacoma, the City of Seattle, the California Attorney General, the California Public Utilities Commission and Puget Sound Energy, Inc. filed petitions for review in the Ninth Circuit. Grays Harbor terminated its participation in the case when Grays Harbor and IPC reached a settlement. On August 24, 2007, the Ninth Circuit issued an opinion in the appeal, 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 submitted by the petitioners for the period January 1, 2000 to June 21, 2001 would have altered the agency's conclusions about refunds and directed the FERC to include sales to the California Department of Water Resources in the proceeding. A number of parties have sought rehearing of the Ninth Circuit's decision. IPC is unable to predict when the Ninth Circuit will rule on the requests for rehearing or the outcome of these matters.

In separate western energy proceedings, the Ninth Circuit issued two decisions on December 19, 2006 regarding the FERC's decisions not to require repricing of certain long term contracts. Those cases originated with individual complaints against specified sellers which did not include IE or IPC. The Ninth Circuit remanded to the FERC for additional consideration the agency's use of restrictive standards of contract review. In its decisions, the Ninth Circuit also questioned the validity of the FERC's administration of its market-based rate regime. The United States Supreme Court has granted certiorari in one of the cases. IPC is unable to predict how or when the Supreme Court will rule, or how the FERC might respond to any such decision or how any such decision might affect the outcome of the Pacific Northwest proceeding.

Western Shoshone National Council: On April 10, 2006, the Western Shoshone National Council (which purports to be the governing body of the Western Shoshone Nation) and certain of its individual tribal members filed a First Amended Complaint and Demand for Jury Trial in the U.S. District Court for the District of Nevada, naming IPC and other unrelated entities as defendants. Plaintiffs allege that IPC's ownership interest in certain land, minerals, water or other resources was converted and fraudulently conveyed from lands in which the plaintiffs had historical ownership rights and Indian title dating back to the 1860's or before.

On May 1, 2006, IPC filed an Answer to plaintiffs' First Amended Complaint denying all liability to the plaintiffs and asserting certain affirmative defenses including collateral estoppel and res judicata, preemption, impossibility and impracticability, failure to join all real and necessary parties, and various defenses based on untimeliness. On June 19, 2006, IPC filed a motion to dismiss plaintiffs' First Amended Complaint, asserting, among other things, that the Court lacks subject matter jurisdiction and that plaintiffs failed to join an indispensable party (namely, the United States government). 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. On June 8, 2007, plaintiffs filed a motion for reconsideration. On January 18, 2008, the District Court denied plaintiffs' motion for reconsideration, and on January 25, 2008 entered judgment in favor of IPC. On January 24, 2008, plaintiffs filed a Notice of Appeal to the Ninth Circuit. IPC and plaintiffs have not yet filed briefs on appeal, although briefing is currently scheduled for completion in April 2008. Oral argument on the appeal has not yet been scheduled. IPC intends to vigorously defend its position in this proceeding, but is unable to predict the outcome of this matter or estimate the impact it may have on IPC's consolidated financial position, results of operations or cash flows.

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

The U.S. District Court has set this matter for trial commencing in April 2008. Discovery in the matter was completed on October 15, 2007. Also in October 2007, the plaintiffs and defendant filed cross-motions for summary judgment on the alleged opacity permit status of this matter. The court has not yet ruled on these motions. IPC is unable to predict the outcome of this matter or estimate the impact it may have on their consolidated financial positions, results of operations or cash flows.

Sierra Club Notice of Intent to File Suit – Boardman: On January 15, 2008, the Oregon Chapter of the Sierra Club, the Northwest Environmental Defense Center, Friends of the Columbia Gorge, Columbia Riverkeeper, and Hells Canyon Preservation Council (collectively, Sierra Club) provided a 60-day notice to Portland General Electric Company (PGE) of intent to file suit. Sierra Club alleges violations of opacity standards at the Boardman coal-fired power plant located in Morrow County, Oregon of which IPC owns ten percent. PGE owns 65 percent and is the operator of the plant. Sierra further alleges various 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. Sierra Club has not yet commenced litigation. Sierra Club alleges thousands of opacity permit limit violations by PGE from and before 2003, and claims that it will seek a declaration that PGE has violated opacity limits, a permanent injunction ordering PGE to comply with such limits, and civil penalties of up to $32,500 per day per violation.

IPC intends to monitor the status of this matter but is unable to predict its outcome or what effect this matter may have on its consolidated financial position, results of operations or cash flows.

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

Plaintiffs have not yet served their complaint on IDACORP or IPC. If the action is pursued by the plaintiffs, the companies intend to vigorously defend their position in this proceeding and believe this matter will not have a material adverse effect on their consolidated financial positions, results of operations or cash flows.

8. BENEFIT PLANS:

SFAS 158

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

The measurement provisions of SFAS 158 are not required to be adopted until 2008 and require that a company measure its plan assets and benefit obligations as of its balance sheet date. IPC already uses a December 31 measurement date for its plans, so adoption of the measurement provisions of SFAS 158 is not expected to have a material effect on IPC's results of operations or cash flows.

Pension Plans

IPC has a noncontributory defined benefit pension plan covering most employees. The benefits under the plan are based on years of service and the employee's final average earnings. IPC's policy is to fund, with an independent corporate trustee, at least the minimum required under the Employee Retirement Income Security Act of 1974 (ERISA) but not more than the maximum amount deductible for income tax purposes. IPC was not required to contribute to the plan in 2007 or 2006. The market-related value of assets for the plan is equal to the fair value of the assets. Fair value is determined by utilizing publicly quoted market values and independent pricing services depending on the nature of the asset, as reported by the trustee/custodian of the plan.

In addition, IPC has a nonqualified, deferred compensation plan for certain senior management employees and directors. This plan was financed by purchasing life insurance policies and investments in marketable securities, all of which are held by a trustee. The cash value of the policies and investments exceed 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 shows the components of net periodic benefit cost for these plans:

	Pension Plan		Deferred Compensation Plan	
	2007	2006	2007	2006
	(thousands of dollars)			
Service cost	$ 15,213	$ 14,476	$ 1,409	$ 1,473
Interest cost	24,457	22,340	2,372	2,327
Expected return on assets	(33,387)	(30,817)	-	-
Amortization of net loss	-	129	566	844
Amortization of prior service cost	650	664	173	245
Amortization of transition asset	-	-	-	-
Net periodic pension cost	$ 6,933	$ 6,792	$ 4,520	$ 4,889

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

	Pension Plan		Deferred Compensation Plan	
	2007	2006	2007	2006
	(thousands of dollars)			
Change in benefit obligation:				
Benefit obligation at January 1	$ 425,599	$ 406,049	$ 41,866	$ 42,723
Service cost	15,213	14,476	1,409	1,473
Interest cost	24,457	22,340	2,372	2,327
Actuarial loss (gain)	(29,585)	(2,827)	(87)	(2,857)
Benefits paid	(15,158)	(14,439)	(2,700)	(2,352)
Plan amendments	-	-	293	552
Benefit obligation at December 31	420,526	425,599	43,153	41,866
Change in plan assets:				
Fair value at January 1	400,924	368,053	-	-
Actual return on plan assets	22,204	47,310	-	-
Benefits paid	(15,158)	(14,439)	-	-
Fair value at December 31	407,970	400,924	-	-
Funded status at end of year	$ (12,556)	$ (24,675)	$ (43,153)	$ (41,866)
Amounts recognized in the statement of financial position consist of:				
Current liabilities	$ -	$ -	$ (2,596)	$ (2,375)
Noncurrent liabilities	(12,556)	(24,675)	(40,557)	(39,491)
Net amount recognized	$ (12,556)	$ (24,675)	$ (43,153)	$ (41,866)
Amounts recognized in accumulated other comprehensive income consist of:				
Net loss	$ 5,954	$ 24,356	$ 9,200	$ 9,853
Prior service cost	3,805	4,455	1,841	1,720
Subtotal	9,759	28,811	11,041	11,573
Less amount recorded as regulatory asset	(9,759)	(28,811)	-	-
Net amount recognized in accumulated other comprehensive income	$ -	$ -	$ 11,041	$ 11,573
Accumulated benefit obligation	$ 346,477	$ 350,434	$ 39,851	$ 38,634

Prior to the adoption of SFAS 158, changes in the Deferred Compensation Plan minimum liability increased other comprehensive income by $2 million in 2006.

In 2008, IPC expects to recognize as components of net periodic benefit cost $1.3 million from amortizing amounts recorded in accumulated other comprehensive income as of December 31, 2007, relating to the pension and deferred compensation plans. This amount consists of $0.6 million of prior service cost for the pension plan and $0.5 million of net loss and $0.2 million of prior service cost for the deferred compensation plan.

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

	2008	2009	2010	2011	2012	2013-2017
			(thousands of dollars)			
Pension Plan	$ 16,507	$ 17,610	$ 18,959	$ 20,512	$ 22,448	$ 145,577
Deferred Compensation Plan	$ 2,672	$ 2,859	$ 3,085	$ 3,142	$ 3,236	$ 18,435

Plan Asset Allocations: IPC's pension plan and postretirement benefit plan weighted average asset allocations at December 31, 2007 and 2006, by asset category are as follows:

	Pension Plan		Postretirement Benefits	
Asset Category	2007	2006	2007	2006
Equity securities	65%	68%	-%	-%
Debt securities	22	24	-	-
Real estate	10	7	-	-
Other (a)	3	1	100	100
Total	100%	100%	100%	100%

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

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

Large-Cap Growth Stocks	12%	International Growth Stocks	7%
Large-Cap Core Stocks	12%	International Value Stocks	7%
Large-Cap Value Stocks	12%	Intermediate-Term Bonds	13%
Small-Cap Growth Stocks	5%	Short-Term Bonds	10%
Small-Cap Value Stocks	5%	Core Real Estate	9%
Micro-Cap Stocks	3%	Private Equity	2%
Cash and Cash Equivalents	3%		

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

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

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

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

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

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

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

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

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

	2007	2006
Service cost	$ 1,368	$ 1,463
Interest cost	3,512	3,426
Expected return on plan assets	(2,777)	(2,523)
Amortization of unrecognized transition obligation	2,040	2,040
Amortization of prior service cost	(535)	(535)
Amortization of net loss	403	812
Net periodic postretirement benefit cost	$ 4,011	$ 4,683

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

	2007	2006
Change in accumulated benefit obligation:		
Benefit obligation at January 1	$ 62,913	$ 63,633
Service cost	1,368	1,463
Interest cost	3,512	3,426
Actuarial (gain) loss	(7,431)	(2,445)
Benefits paid	(3,536)	(3,164)
Benefit obligation at December 31	56,826	62,913
Change in plan assets:		
Fair value of plan assets at January 1	32,627	29,893
Actual return on plan assets	3,129	3,158
Employer contributions	2,876	2,004
Benefits paid	(3,536)	(2,428)
Fair value of plan assets at December 31	35,096	32,627

Funded status at end of year (included in noncurrent liabilities)	$ (21,730)	$ (30,286)

Amounts recognized in accumulated other comprehensive income consist of:

Net loss	$ 3,900	$ 12,086
Prior service cost (credit)	(2,607)	(3,142)
Transition obligation	10,200	12,240
Subtotal	11,493	21,184
Less amount recognized in regulatory assets	8,006	17,370
Less amount included in deferred tax assets	3,487	3,814
Net amount recognized in accumulated other comprehensive income	$ -	$ -

In 2008, IPC expects to recognize as components of net periodic benefit cost $1.5 million from amortizing amounts recorded in accumulated other comprehensive income as of December 31, 2007 relating to the postretirement plan. This amount consists of ($0.5) million of prior service cost and $2.0 million of transition obligation.

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

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

	2008	**2009**	**2010**	**2011**	**2012**	**2013-2017**
Expected benefit payments*	$ 4,100	$ 4,300	$ 4,400	$ 4,600	$ 4,800	$ 25,600
Expected Medicare Part D subsidy receipts	$ 500	$ 500	$ 600	$ 600	$ 700	$ 4,600

*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 benefits covered by the plan was 6.75 percent in 2007 and 2006. A one-percentage point change in the assumed health care cost trend rate would have the following effect (in thousands of dollars):

	1-Percentage-Point	
	Increase	**Decrease**
Effect on total of cost components	$ 258	$ (195)
Effect on accumulated postretirement benefit obligation	$ 2,144	$ (1,696)

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

	Pension Benefits		**Postretirement Benefits**	
	2007	**2006**	**2007**	**2006**
Discount rate	6.4%	5.85%	6.4%	5.85%

Rate of compensation increase	4.5%	4.5%	-	-
Medical trend rate	-	-	6.75%	6.75%
Measurement date	12/31/07	12/31/06	12/31/07	12/31/06

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

	Pension Benefits		**Postretirement Benefits**	
	2007	**2006**	**2007**	**2006**
Discount rate	5.85%	5.6%	5.85%	5.6%
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	-	-	6.75%	6.75%

Employee Savings Plan

IPC has an Employee Savings Plan that complies with Section 401(k) of the Internal Revenue Code and covers substantially all employees. IPC matches specified percentages of employee contributions to the plan. Matching contributions amounted to $5 million in 2007 and $4 million in 2006.

Postemployment Benefits

IPC provides certain benefits to former or inactive employees, their beneficiaries and covered dependents after employment but before retirement. These benefits include salary continuation, health care and life insurance for those employees found to be disabled under IPC's disability plans and health care for surviving spouses and dependents. IPC accrues a liability for such benefits. The post employment benefit amounts included in other deferred credits on IPC's consolidated balance sheets at December 31 are $3.5 million and $4.0 million for 2007 and 2006, respectively.

Pension Protection Act

In 2006, the Pension Protection Act of 2006 (the Act), which affects the manner in which many companies, including IDACORP and IPC, administer their pension plans was signed into law. The Act made changes to a variety of rules that apply to employee benefit plans, including those dealing with minimum funding requirements of defined benefit pension plans and plan investments of defined contribution pension plans. The Act also permanently extended the pension law changes made by the Economic Growth and Tax Relief Reconciliation Act of 2001, which had been scheduled to sunset on December 31, 2010. This legislation became effective on January 1, 2008. Due to the funded status and funding policy of IPC's pension plan, the Act is not expected to have a material impact on the results of operations, financial condition, cash flows or liquidity of IPC when it was implemented.

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

The following table presents the major classifications of IPC's utility plant in service, annual depreciation provisions as a percent of average depreciable balance and accumulated provision for depreciation for the years 2007 and 2006 (in thousands of dollars):

	2007		**2006**	
	Balance	**Avg Rate**	**Balance**	**Avg Rate**
Production	$ 1,639,710	2.52%	$ 1,592,790	2.55%
Transmission	684,399	2.13	606,947	2.18
Distribution	1,175,429	2.58	1,097,390	2.60
General and Other	296,801	8.29	286,567	6.74
Total in service	3,796,339	2.95%	3,583,694	2.75%
Accumulated provision for depreciation	(1,468,832)		(1,406,210)	
In service - net	$ 2,327,507		$ 2,177,484	

IPC has interests in three jointly-owned generating facilities. Under the joint operating agreements, each participating utility is responsible for financing its share of construction, operating and leasing costs. IPC's proportionate share of direct operation and maintenance expenses applicable to the projects is included in the Consolidated Statements of Income. These facilities, and the extent of IPC's participation, were as follows at December 31, 2007 (in thousands of dollars):

Name of Plant	Location	Utility Plant In Service	Construction Work in Progress	Accumulated Provision for Depreciation	Owner ship %	MW*
Jim Bridger Units 1-4	Rock Springs, WY	$ 474,759	$ 8,802	$ 271,777	33	771
Boardman	Boardman, OR	70,294	161	49,288	10	64
Valmy Units 1 and 2	Winnemucca, NV	331,371	6,958	213,430	50	284

*IPC share of nameplate capacity

IPC's wholly-owned subsidiary, Idaho Energy Resources Co., is a joint venturer in Bridger Coal Company, which operates the mine supplying coal to the Jim Bridger generating plant. IPC's coal purchases from the joint venture were $51 million and $52 million in 2007 and 2006, respectively.

IPC has contracts to purchase the energy from four PURPA qualified facilities that are 50 percent owned by Ida-West. IPC's power purchases from these facilities were $8 million annually in 2007 and 2006.

10. INVESTMENTS:

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

	2007	2006
IPC Investments:		
Equity method investment	$ 76,451	$ 62,223
Available-for-sale equity securities	21,445	21,548
Executive deferred compensation	6,627	6,492
Other investments	5	4
Total IPC investments	104,528	90,267

Equity Method Investments

IPC, through its subsidiary Idaho Energy Resources Co., is a 33 percent owner of Bridger Coal Company, which supplies coal to the Jim Bridger generating plant owned in part by IPC. Ida-West, through separate subsidiaries, owns 50 percent of each of the following electric generation projects: South Forks Joint Venture; Hazelton/Wilson Joint Venture and Snow Mountain Hydro LLC.

IFS invests in affordable housing developments that are accounted for in accordance with APB 18, *"The Equity Method of Accounting for Investments in Common Stock"* and Emerging Issues Task Force Issue 94-1, *"Accounting for Tax Benefits Resulting from Investments in Affordable Housing Projects,"* and are presented as Investments on the Consolidated Balance Sheets. All projects are reviewed periodically for impairment.

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

	2007	2006
Bridger Coal Company (IPC)	$ 5,553	$ 9,347

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

	2007	2006
Operating revenues	$ 153,126	$ 154,910
Operating expenses	136,468	126,869

Net Income	$	16,658	$	28,041

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

		2007		2006
Assets				
Current assets	$	58,672	$	47,723
Noncurrent assets		330,583		325,252
Total Assets	$	389,255	$	372,975
Liabilities				
Current liabilities	$	25,372	$	28,250
Noncurrent liabilities		134,529		158,054
Total Liabilities		159,901		186,304
Joint venture capital		229,353		186,671
Total Liabilities and Joint Venture Capital	$	389,254	$	372,975

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

Investments classified as held-to-maturity securities are reported at amortized cost. Held-to-maturity securities are investments in debt securities for which the company has the positive intent and ability to hold the securities until maturity. These debt securities have maturities ranging from 2008 through 2025.

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

	2007			2006		
	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
Available-for-sale securities (IPC)	$ 1,059	$ 128	$ 21,445	$ 2,474	$ 322	$ 21,548

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

		2007		2006
Proceeds from sales	$	26,110	$	20,778
Gross realized gains from sales		2,093		3,774
Gross realized losses from sales		762		280

Additionally, these investments are evaluated to determine whether they have experienced a decline in market value that is considered other-than-temporary. IPC analyzes securities in loss positions as of the end of each reporting period. Any security with an unrealized loss of more than 20 percent is evaluated for other-than-temporary impairment. A security will generally be written down to market value if it has an unrealized loss of 20 percent or more for more than nine months. If additional information is available that indicates a security is other-than-temporarily impaired, it will be written down prior to the nine-month time period. In the alternative, if a security has been impaired for more than nine months but available information indicates that the impairment is temporary, the security will not be written down. IPC has not recognized any other-than-temporary impairments in 2007 or 2006.

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

	Less than 12 months		12 months or longer	
	Aggregate Unrealized Loss	Aggregate Related Fair Value	Aggregate Unrealized Loss	Aggregate Related Fair Value
2007 Available-for-sale equity securities	$ 128	$ 1,059	$ -	$ -
2006 Available-for-sale equity securities	$ 241	$ 3,879	$ 81	$ 621

The available-for-sale equity securities in unrealized loss positions are diversified investments in common stock of various companies used to fund IPC's Senior Management Security Plan. The held-to-maturity debt securities in unrealized loss positions are bonds, whose market values fluctuate based on the interest rate environment. At December 31, 2007, one available-for-sale and two held-to-maturity securities were in an unrealized loss position. None of these securities had unrealized loss positions of greater than 20 percent. At December 31, 2006, eleven available-for-sale and six held-to-maturity securities were in an unrealized loss position. None of these securities had unrealized loss positions of greater than 20 percent. IPC does not consider these investments to be other-than-temporarily impaired at December 31, 2007 or 2006.

11. FAIR VALUE OF FINANCIAL INSTRUMENTS:

The estimated fair value of IPC's financial instruments has been determined 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, long-term debt and investments are based upon quoted market prices of the same or similar issues or discounted cash flow analyses as appropriate.

	December 31, 2007		**December 31, 2006**	
	Carrying Amount	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
		(thousands of dollars)		
Assets:				
Notes receivable	$ 4,859	$ 4,907	$ 5,853	$ 5,679
Investments	23,848	23,848	28,040	28,040
Liabilities:				
Long-term debt	$ 1,145,981	$ 1,136,042	$ 987,045	$ 978,491

12. ASSET RETIREMENT OBLIGATIONS (ARO):

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

IPC's recorded AROs relate to: removal of PCB-contaminated equipment at its distribution facilities and the reclamation and removal costs at its jointly owned coal-fired generation facilities. In 2007 changes in estimates were identified at IPC and IPC's jointly owned coal-fired generation facilities resulting in a net increase in liability of $0.9 million.

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

The regulated operations of IPC also collect removal costs in rates for certain assets that do not have associated AROs. The adoption of SFAS 143 required IPC to redesignate these removal costs as regulatory liabilities. Costs recorded as regulatory liabilities on IPC's Consolidated Balance Sheet as of December 31, 2007 and 2006, were $155 million and $156 million, respectively.

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

	IPC	
	2007	**2006**
Balance at beginning of year	$ 12,911	$ 10,079
Accretion expense	692	628
Revisions in estimated cash flows	920	-
Liability incurred	-	2,204
Liability settled	(8)	-
Balance at end of year	$ 14,515	$ 12,911

13. RELATED PARTY TRANSACTIONS (IPC):

IDACORP

IPC performs corporate functions such as financial, legal and management services for IDACORP and its subsidiaries. IPC charges IDACORP for the costs of these services based on service agreements and other specifically identified costs. For these services IPC billed IDACORP $2 million in 2007 and $4 million in 2006.

Ida-West

IPC purchases all of the power generated by four of Ida-West's hydroelectric projects located in Idaho. IPC paid $8 million in both 2007 and 2006.

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Ida-West

IPC purchases all of the power generated by four of Ida-West's hydroelectric projects located in Idaho. IPC paid $8 million in both 2007 and 2006.

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	04/11/2008	End of 2007/Q4

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

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

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year	2,725,005	(6,150,330)		
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	(2,127,497)			
3	Preceding Quarter/Year to Date Changes in Fair Value	713,442	6,150,330		(7,048,073)
4	Total (lines 2 and 3)	(1,414,055)	6,150,330		(7,048,073)
5	Balance of Account 219 at End of Preceding Quarter/Year	1,310,950			(7,048,073)
6	Balance of Account 219 at Beginning of Current Year	1,310,950			(7,048,073)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	(922,013)			450,330
8	Current Quarter/Year to Date Changes in Fair Value	178,312			(126,006)
9	Total (lines 7 and 8)	(743,701)			324,324
10	Balance of Account 219 at End of Current Quarter/Year	567,249			(6,723,749)

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			(3,425,325)		
2			(2,127,497)		
3			(184,301)		
4			(2,311,798)	93,929,189	91,617,391
5			(5,737,123)		
6			(5,737,123)		
7			(471,683)		
8			52,306		
9			(419,377)	76,579,025	76,159,648
10			(6,156,500)		

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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	04/11/2008	End of 2007/Q4

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

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

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	3,796,793,711	3,796,793,711
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	3,796,793,711	3,796,793,711
9	Leased to Others		
10	Held for Future Use	3,365,527	3,365,527
11	Construction Work in Progress	257,589,900	257,589,900
12	Acquisition Adjustments	-454,449	-454,449
13	Total Utility Plant (8 thru 12)	4,057,294,689	4,057,294,689
14	Accum Prov for Depr, Amort, & Depl	1,468,831,768	1,468,831,768
15	Net Utility Plant (13 less 14)	2,588,462,921	2,588,462,921
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	1,430,468,593	1,430,468,593
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	38,713,478	38,713,478
22	Total In Service (18 thru 21)	1,469,182,071	1,469,182,071
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	-350,303	-350,303
33	Total Accum Prov (equals 14) (22,26,30,31,32)	1,468,831,768	1,468,831,768

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

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

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	62,160	-56,457
3	(302) Franchises and Consents	21,711,627	60,002
4	(303) Miscellaneous Intangible Plant	50,320,243	6,491,116
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	72,094,030	6,494,661
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,370,319	
9	(311) Structures and Improvements	130,536,694	964,932
10	(312) Boiler Plant Equipment	505,458,266	24,736,981
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	122,585,943	7,674,363
13	(315) Accessory Electric Equipment	61,359,209	309,204
14	(316) Misc. Power Plant Equipment	13,086,514	1,942,279
15	(317) Asset Retirement Costs for Steam Production	3,836,568	894,668
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	838,233,513	36,522,427
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	22,523,451	4,906,033
28	(331) Structures and Improvements	133,690,047	11,955,032
29	(332) Reservoirs, Dams, and Waterways	244,621,041	1,461,865
30	(333) Water Wheels, Turbines, and Generators	187,440,908	480,338
31	(334) Accessory Electric Equipment	36,805,775	941,185
32	(335) Misc. Power PLant Equipment	15,590,447	701,236
33	(336) Roads, Railroads, and Bridges	6,950,430	542,255
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	647,622,099	20,987,944
36	D. Other Production Plant		
37	(340) Land and Land Rights	402,745	
38	(341) Structures and Improvements	5,301,732	464,215
39	(342) Fuel Holders, Products, and Accessories	3,520,611	245,078
40	(343) Prime Movers	29,957,033	28,495,093
41	(344) Generators	61,685,462	-40,203,128
42	(345) Accessory Electric Equipment	4,681,678	9,373,969
43	(346) Misc. Power Plant Equipment	1,385,245	872,982
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	106,934,506	-751,791
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,592,790,118	56,758,580

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

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

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.
7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.
8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.
9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			5,703		2
5			21,771,624		3
7,796,777			49,014,582		4
7,796,782			70,791,909		5
					6
					7
			1,370,319		8
57,744			131,443,882		9
5,475,988			524,719,259		10
					11
3,326,718			126,933,588		12
62,678			61,605,735		13
401,099			14,627,694		14
			4,731,236		15
9,324,227			865,431,713		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
297,607			27,131,877		27
295,633			145,349,446		28
25,000			246,057,906		29
65,312			187,855,934		30
173,471			37,573,489		31
2,954			16,288,729		32
			7,492,685		33
					34
859,977			667,750,066		35
					36
			402,745		37
			5,765,947		38
			3,765,689		39
14,854,734			43,597,392		40
-15,200,000			36,682,334		41
			14,055,647		42
			2,258,227		43
					44
-345,266			106,527,981		45
9,838,938			1,639,709,760		46

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	28,752,863	2,341,500
49	(352) Structures and Improvements	36,782,554	3,528,731
50	(353) Station Equipment	245,790,680	19,364,986
51	(354) Towers and Fixtures	98,003,480	23,794,427
52	(355) Poles and Fixtures	77,282,453	11,453,638
53	(356) Overhead Conductors and Devices	120,016,810	19,772,786
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)	606,947,191	80,256,068
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	4,607,315	-221,040
61	(361) Structures and Improvements	20,494,136	1,175,996
62	(362) Station Equipment	142,958,358	9,392,314
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	194,701,580	11,386,049
65	(365) Overhead Conductors and Devices	98,919,001	9,243,475
66	(366) Underground Conduit	43,632,849	2,652,267
67	(367) Underground Conductors and Devices	162,348,862	10,048,775
68	(368) Line Transformers	318,762,025	40,578,706
69	(369) Services	51,272,410	3,061,264
70	(370) Meters	52,622,132	4,936,677
71	(371) Installations on Customer Premises	2,634,033	139,954
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	4,067,070	128,960
74	(374) Asset Retirement Costs for Distribution Plant	370,187	-110,923
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,097,389,958	92,412,474
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	8,760,765	146,931
87	(390) Structures and Improvements	64,391,078	5,135,502
88	(391) Office Furniture and Equipment	37,350,131	8,194,723
89	(392) Transportation Equipment	51,050,749	7,196,442
90	(393) Stores Equipment	982,361	185,107
91	(394) Tools, Shop and Garage Equipment	4,222,287	289,705
92	(395) Laboratory Equipment	9,761,135	634,673
93	(396) Power Operated Equipment	7,306,985	1,403,340
94	(397) Communication Equipment	28,196,828	158,705
95	(398) Miscellaneous Equipment	2,904,743	179,122
96	SUBTOTAL (Enter Total of lines 86 thru 95)	214,927,062	23,524,250
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)	214,927,062	23,524,250
100	TOTAL (Accounts 101 and 106)	3,584,148,359	259,446,033
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	3,584,148,359	259,446,033

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
92			31,094,271		48
56,989			40,254,296		49
2,177,755			262,977,911		50
56,209			121,741,698		51
375,227			88,360,864		52
137,462			139,652,134		53
					54
					55
			318,351		56
					57
2,803,734			684,399,525		58
					59
493			4,385,782		60
12,680			21,657,452		61
667,925			151,682,747		62
					63
2,145,266			203,942,363		64
1,650,661			106,511,815		65
155,959			46,129,157		66
1,243,316			171,154,321		67
6,699,825			352,640,906		68
445,996			53,887,678		69
1,235,877			56,322,932		70
41,007			2,732,980		71
					72
74,757			4,121,273		73
			259,264		74
14,373,762			1,175,428,670		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
34,566			8,873,130		86
734,902			68,791,678		87
7,349,071			38,195,783		88
990,416			57,256,775		89
92,789			1,074,679		90
101,766			4,410,226		91
163,390			10,232,418		92
361			8,709,964		93
2,462,397			25,893,136		94
57,807			3,026,058		95
11,987,465			226,463,847		96
					97
					98
11,987,465			226,463,847		99
46,800,681			3,796,793,711		100
					101
					102
					103
46,800,681			3,796,793,711		104

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2008	End of 2007/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			185,246
4	Transmission Stations			360,819
5	Transmission Lines			69,263
6	Distribution Stations			1,137,976
7	Beacon Light Substation (1)	12/30/02		465,662
8				
9				
10	Boise Operations Center	12/31/82		72,785
11	Boise Mechanical and Electrical Shop	12/31/01		47,000
12	Transmission Stations	12/31/81		178,094
13	Distribution Stations			80,306
14				
15				
16				
17				
18				
19	Column B if no date listed it is various			
20				
21	Other Property:			
22				
23				
24				
25				
26				
27	(1) a portion of Beacon Light was classified in			
28	account 101000 in the prior year. In 2007 it			
29	was reclassified to account 105000.			
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			3,365,528

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	04/11/2008	End of 2007/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	DANSKIN UNIT #1 - 160 MW CT (2	47,664,001
2	ROLLUP RELIC COST BROWNLEE	37,166,859
3	ROLLUP RELIC COST HELLS CANYON	25,469,840
4	ROLLUP RELIC COST OXBOW	11,672,742
5	T7230601 DANSKIN-HUBBARD 230 K	8,932,442
6	HELLS CANYON RELICENSING OUTSI	8,342,890
7	CIAC LIABILITY RECLASS	7,226,739
8	TURBINE BLADES AND VANES - CAP	5,745,426
9	VALMY UNDISTRIBUTED WORK ORDER	3,922,799
10	DANSKIN-BENNETT 230 KV	3,021,500
11	CRBU0601 SERIES CAPACITOR	2,813,120
12	AP ACCRUAL ESTIMATE	2,798,000
13	WQ - ONGOING HELLS CANYON RELI	2,679,679
14	PURCHASE STAR PROPERTY FOR NOR	2,629,980
15	LOWER MALAD FISH PASSAGE	2,561,437
16	INSTALL 230KV PHASE SHIFTER AT	2,277,515
17	MAINFRAME UPGRADE	2,234,580
18	BUILD NEW POLE LINE SUBSTATION	2,149,526
19	MOBILE WORKFORCE MANAGEMENT 20	2,076,833
20	ENTERPRISE STORAGE	2,074,637
21	BRIDGER UNDISTRIBUTED WORK ORD	2,032,908
22	HCC RELICENSING FISH2004 FEASI	1,768,350
23	DNPR0601 NETWORK	1,442,887
24	SPVY0502-NEW 138-12.5KV SUBSTA	1,418,087
25	REL-HELLS CANYON COMPLEX FY200	1,404,936
26	DNPR-MNJ1 REBUILD LINE 919 WI	1,380,996
27	PURCHASE MCCALL PROPERTY FOR O	1,358,663
28	VALMY 34534 U1 OVERFIRE AIR SY	1,344,833
29	HUBBARD NEW 230 KV SWITCHING S	1,330,097
30	LINE 470 CONSTRUCTION NWMS-MCA	1,328,047
31	VALMY 98196159 RELINE EVAPORAT	1,298,792
32	#3 CONTROL AND EQUIPMENT UPGRA	1,236,191
33	NWTF 138 KV TAP	1,191,093
34	COST CENTER 317 DELIVERY CAPIT	1,183,991
35	REPLACE METALCLAD	1,183,464
36	MCAL0503-CONVERT 69KV TO 138KV	1,154,869
37	342 COST CENTER DELIVERY CAPIT	1,153,474
38	REPLACE NMPA METALCLAD SECT.1	1,093,806
39	WATER MGMT-SHOP BUILDING PURCH	1,076,468
40	DNPR0601 OPERATIONS	990,887
41	LINE 470 CONSTRUCTION STKY-TMR	987,211
42	326-COST CENTER DELIVERY CAPIT	958,530
43	TOTAL	257,589,900

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	BMPR - 230KV LINE TERMINAL	945,082
2	RIVER ENG.-HELLS CANYON CONTIN	938,195
3	MPSN - MIDPOINT EAST RAS UPGRA	922,068
4	HCC RELICENSING, FISH2004 ANAD	875,996
5	ROLLUP RELIC COST SWAN FALLS	875,241
6	SWAN FALLS RELICENSING	853,969
7	DONN0701 INSTALL 80MVAR 138KV	845,909
8	RIVER ENG.-HELLS CANYON CONTIN	815,091
9	HCC RELICENSING, FISH2004 REDB	804,872
10	OP. HYDRO. - PHASE V STREAMFLO	728,096
11	HCC RELICENSING, FISH2004 INST	724,668
12	JIM BRIDGER RAS-A AND RAS-B	723,455
13	PAYROLL & IBNR ACCRUAL	699,383
14	MS SQL SERVER CLUSTER	689,058
15	392 COST CENTER DELIVERY CAPIT	669,330
16	341 COST CENTER DELIVERY CAPIT	642,430
17	REL-HCC OREGON REAUTHORIZATION	635,001
18	PASSPORT NEW USER INTERFACE	624,926
19	IPCO*CONVERT HAVN TO 138 KV	622,739
20	NWMS0501 - CONVERT TO 138KV	615,205
21	CARD ACCESS CONTROL SYSTEM	606,310
22	418-CC DELIVERY CAPITAL OVERHE	597,416
23	390 COST CENTER DELIVERY CAPIT	596,099
24	PURCHASE #4 TURBINE RUNNER	592,358
25	343 COST CENTER DELIVERY CAPIT	591,075
26	IPCO/BOIS-014/2006 DOWNTOWN CA	546,241
27	HCC RELICENSING FISH2004 RESID	542,226
28	LEGAL DEPT. LABOR FOR RELICENS	527,986
29	LEADERSHIP TRANSFORMATION	509,937
30	BUILD NEW ADRIAN SUBSTATION AT	509,180
31	CONSTRUCTION ACCOUNTING CAPITA	497,493
32	415-CC DELIVERY CAPITAL OVERHE	472,478
33	335-COST CENTER DELIVERY CAPIT	455,863
34	LSPO LICENSE ART 414 REC - REN	451,045
35	REL - SWAN FALLS FY2004 CAPITA	445,941
36	NETWORK BACKBONE UPGRADE	445,938
37	336-COST CENTER DELIVERY CAPIT	425,249
38	T7230701 OPGW DANSKIN-HUBBARD	417,864
39	BRIDGER 2008C002 U4 REHEATER R	416,467
40	578 COST CENTER DELIVERY CAPIT	413,098
41	577 COST CENTER DELIVERY CAPIT	406,107
42	ROW FOR T404 - 138 KV TO CHERR	401,466
43	TOTAL	257,589,900

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	04/11/2008	End of 2007/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	IPCO*UPGRADE PNGE TO FACILITAT	401,208
2	COST CENTER 316 DELIVERY CAPIT	400,193
3	LINE 438, PERMITTING & ROW FOR	389,393
4	IPCO*PURCHASE ROW FOR LINE #22	383,794
5	COM - REC BAKER CO SETTLEMENT	382,166
6	300T GANTRY CRANE MODERNIZATIO	377,118
7	HAILEY TEAM CAP OH WORK ORDER	371,870
8	IPCO/HBND-041 REBUILD APPROX 3	368,204
9	BRIDGER 2007C177 U3 BURNER COR	365,661
10	WQ SWAN FALLS RELICENSING-CAPI	358,028
11	WHITETAIL SUBDIVISION-LINE EXT	357,466
12	CAPITAL OVERHEADS FOR CADD & A	352,990
13	BRIDGER 2007C042 U3 WATERWALL	349,570
14	BRIDGER 2007C174 U3 REPL LOWER	340,588
15	TFOC SILVERS BUILDING GARAGE A	336,080
16	REC - BAKER COUNTY SETTLEMENT	328,660
17	CDAL-013 TRANSFER TO NEW CDAL-	326,755
18	HOMEDALE SUBSTATION UPGRADE LA	323,822
19	MPSN0703 - REBUILD 311Z S&C CI	316,200
20	ADEL0702 - ADD THERMAL DETECTI	315,505
21	GOODING TEAM CAP OH WORK ORDER	309,488
22	LINE 438, RIGHT OF WAY, VICTOR	294,860
23	BRDY0702 - REPLACE CONDENSER C	293,956
24	IDAHO POWER PACIFICORP JOINT V	293,673
25	BRIDGER 2007C041 U3 WALLBLOWER	290,377
26	VALMY 98192448 PURCHASE BALANC	276,795
27	REPLACE #5 VOLTAGE REGULATOR &	274,069
28	CALL CENTER LABOR HOURS FOR LI	272,453
29	IPCO REBUILD 2 MI NORTH OF NOR	270,297
30	Delivery Overheads	269,832
31	IPCO/BOIS-021/2006 DOWNTOWN CA	266,780
32	CJ STRIKE: #1 TURBINE RUNNER	263,514
33	TWINWEST TEAM CAP OH WORK ORDE	261,203
34	SWAN FALLS RELICENSING FISH200	258,694
35	RC RELOCATE BOIS	257,648
36	585 COST CENTER DELIVERY CAPIT	254,934
37	575 COST CENTER DELIVERY CAPIT	251,809
38	BRIDGER 2007C809 REPL U3 UPPER	250,379
39	EASTGATE SUBSTATION - ADD FEED	247,210
40	ENHANCED LAW ENFORCEMENT PER S	246,492
41	STATION APP. LAB EQUIP. 2007	243,299
42	381 -COST CENTER DELIVERY CAPI	243,141
43	TOTAL	257,589,900

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	04/11/2008	End of 2007/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	REL - REC SWAN FALLS RELICENSI	241,140
2	SIEM - SECURITY INFORMATION EV	231,965
3	REMOTE DEVICE SECURITY & MANAG	231,671
4	TERR: HCC RELICENSING	228,389
5	OLD CUTTERS SUBDIVISION-RESIDE	228,264
6	100-COST CENTER DELIVERY CAPIT	226,784
7	LINE #902, REPLACE LEANING STR	224,239
8	ADAMSFAM TEAM CAP OH WORK ORDE	219,688
9	PORT AUTHORITY & WIRELESS DEPL	217,157
10	MOSCA SECA SUB #1- PRI & SEC T	217,155
11	CDAL ADD VTRY 138 LINE TERMINA	211,752
12	410-CC DELIVERY CAPITAL OVERHE	211,301
13	DELIVERY WORK ORDER RECON PROJ	210,633
14	DELIVERY CAPITAL OVERHEADS FOR	209,917
15	IPCO SIPN 041 2006 CABLE REPLA	207,947
16	VALMY 98191438 ETAPRO PERFORMA	207,394
17	455-COST CENTER DELIVERY CAPIT	207,197
18	BRIDGER 2007C159 COAL PILE LIG	206,584
19	LSPO LICENSE ART 414 REC - RIV	206,512
20	MC CALL ENGINEERING EMERGENCY	201,197
21	AFTS0702 - REPAIR CABLE TRAYS	199,101
22	WEB SITE REDESIGN	198,447
23	334-COST CENTER DELIVERY CAPIT	197,461
24	COST CENTER 310 DELIVERY CAPIT	197,337
25	BRIDGER 2007C036 INST ZOLOBOSS	196,201
26	BOARDMAN 22163 UPG DCS TO OVAT	195,609
27	BEARING COOLERS, CLOSED LOOP S	194,841
28	370 -COST CENTER DELIVERY CAPI	193,850
29	L-406, MTN HM JCT- UPPER SALMO	193,340
30	TOOL EXP TRANS TO CONST	188,428
31	420-CC DELIVERY CAPITAL OVERHE	188,268
32	153 COST CENTER DELIVERY CAPIT	186,666
33	BRIDGER 2007C234 REPL D10 DOZE	185,786
34	BRIDGER 2007C063 U3 SH HEAVY W	184,840
35	TFEAST TEAM CAP OH WORK ORDER	184,036
36	FALLS - RELAY REPLACEMENT	183,967
37	IPCO- ELMR 042 SINGLE PHASE RE	183,425
38	BRIDGER 2007C911 PLANT SECURIT	182,511
39	BORA0501 BORA-MPSN 345KV THER	182,207
40	MINI CASSIA TEAM CAP OH WORK O	181,310
41	NEW MEADOWS EAST NEW OO ACSR O	178,354
42	LAKE SHORE SUBSTATION - PURCHA	178,055
43	TOTAL	257,589,900

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	04/11/2008	End of 2007/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	PQ AG DSR LAB EQUIPMENT-ION	176,203
2	ETGT-018, INSTALL NEW OH FEEDE	175,225
3	REL - REC HCC RELICENSING PROC	173,992
4	CITY OF KETCHUM-RELOCATE O/H T	170,977
5	L-103, AFTS-BNCK 46KV, PATROL	170,049
6	IPCO/VTRY 013/ F60/ 2007 CABLE	169,105
7	324-COST CENTER DELIVERY CAPIT	168,860
8	IPCO-NEW FEEDER POLN 012 TO 25	168,848
9	BRIDGER 2007C105 REPL PLANT CO	168,510
10	856 COST CENTER DELIVERY CAPIT	168,428
11	458-COST CENTER DELIVERY CAPIT	168,221
12	EKRT-041 ADD PHASES, SPLIT LOA	167,743
13	378 -COST CENTER DELIVERY CAPI	165,192
14	404 COST CENTER DELIVERY CAPIT	164,052
15	BRIDGER 2007C157 U2 NEURAL NET	163,592
16	DNPR0601 INTERCONNECT	163,255
17	2007 PC PURCHASES - CAPITAL RE	162,212
18	BORA: RAS C & D COMMUNICATIONS	159,927
19	PERRY VANPATTEN TIME WORK ORDE	158,724
20	375 COST CENTER DELIVERY CAPIT	157,901
21	JIM BRIDGER SUBSTATION CAPITAL	156,602
22	MICRON, ADDITIONAL 3750 KVA	155,229
23	BRIDGER 2007C201 U4 EXCITATION	153,250
24	REPLACE UNIT TRASHRACK	153,153
25	AFTS0701 - REPL 11 AB SWITCHES	149,145
26	CRIMSON PT #5	148,621
27	584 COST CENTER DELIVERY CAPIT	148,459
28	VALLEY CLUB WEST NINE SUBD-HAI	145,683
29	UI VERSION J IMPLEMENTATION	141,328
30	T7110401-HPVY 230KV DOUBLE CIR	140,499
31	210-COST CENTER DELIVERY CAPIT	136,922
32	BRIDGER 2007C727 REPL BOILER B	136,630
33	IPCO*PERMIT / PURCHASE ROW FOR	136,615
34	353 COST CENTER DELIVERY CAPIT	136,033
35	BRIDGER 2007C184 COAL SILO LIN	134,340
36	BUILD NEW DRAFT TUBE GATES FOR	134,207
37	COST CENTER 318 DELIVERY CAPIT	132,468
38	HSDL-NEW STATION	128,438
39	IPCO-NEW FEEDER POLN 011 TO GR	128,409
40	COST CENTER 329 DELIVERY CAPIT	126,228
41	RIVER ENG-SWAN FALLS RELICENSI	125,242
42	JT GREYHAWK SUB 1-LINDER & HUB	125,110
43	TOTAL	257,589,900

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	MPSN: RAS C & D COMMUNICATIONS	125,073
2	IPCO/ NMPA-019 RECONDUCTOR 1.5	124,058
3	LINE#220 69 KV TSPO-MTCY-2007	123,369
4	NEW UNIT 7573 - CC 848 BRET JU	122,732
5	POLE LINE SUBSTATION LAND ACQU	122,556
6	FRMT0701 - REPLACE 131H WITH A	122,521
7	345 COST CENTER DELIVERY CAPIT	121,878
8	BRIDGER 2007C197 REPL 41 FEEDW	121,740
9	IPCO-EDEN041-RELIABLITY MAINTE	120,982
10	BOARDMAN 24554 REWIND GENERATO	120,659
11	KINPORT: RAS C & D COMMUNICATI	120,310
12	INTERWOVEN LICENSES	119,075
13	300 COST CENTER DELIVERY CAPIT	116,566
14	377 -COST CENTER DELIVERY CAPI	116,492
15	356 COST CENTER DELIVERY CAPIT	115,150
16	TERR: DC POWDER RIVER IRRIGATI	114,129
17	OXBOW FISH HATCHERY EXPANSION	114,055
18	OUT OF WARRANTY SERVER REPLACE	113,937
19	VALE-013 REBUILD 3 MI FROM R53	113,428
20	BRIDGER 2007C190 REAL TIME CON	113,247
21	IPCO/FLTP12-DAMAGE DUE TO FIRE	111,898
22	BRIDGER 2007C211 U4 CLEAN AIR	111,609
23	CEDAR CROSSING SUBD #1- 117 LO	110,469
24	421-CC DELIVERY CAPITAL OVERHE	110,468
25	IPCO/RELOCATE RG60/INST NEW RE	109,681
26	CJ STRIKE: ADMIN COMPLEX	108,938
27	COST CENTER 290 DELIVERY CAPIT	108,324
28	IPCO/BOBN 042/ F109/ 2007 CABL	106,974
29	BRIDGER 2007C079 U2 REPL 10 CO	106,687
30	SPC TEST EQUIPMENT-POCATELLO	105,538
31	HOMESTEAD ROAD WORK ASSOCIATED	105,230
32	VM WARE 3.0	104,617
33	CANYON REGION MANAGER LABOR AN	104,468
34	BOARDMAN 23686 INSTALL TRAININ	104,322
35	ELKHORN SPRINGS - SUN VALLEY/	103,902
36	MPSN0702 - REPLACE 230KV BREAK	103,137
37	IPCO-MCAL42 SUBSTATION GETAWAY	102,124
38	BRIDGER 2007C186 U1 MERCURY CE	101,913
39	BRIDGER 2007C188 U2 MERCURY CE	101,867
40	BRIDGER 2007C187 U3 MERCURY CE	101,867
41	BRIDGER 2007C185 U4 MERCURY CE	101,867
42	1998 NEAR EAST IDAHO VESTED I	101,493
43	TOTAL	257,589,900

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	04/11/2008	End of 2007/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	EEM SOFTWARE	101,446
2	BTLR-REPLACE FEEDER RELAYS	100,068
3	OTHER MINOR PROJECTS	-13,169,367
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43	TOTAL	257,589,900

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

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

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

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	1,367,808,581	1,367,808,581		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	94,999,200	94,999,200		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	2,883,045	2,883,045		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9	Fuel Stock	114,301	114,301		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	97,996,546	97,996,546		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	38,671,143	38,671,143		
13	Cost of Removal	10,817,357	10,817,357		
14	Salvage (Credit)	13,131,002	13,131,002		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	36,357,498	36,357,498		
16	Other Debit or Cr. Items (Describe, details in footnote):	1,020,964	1,020,964		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,430,468,593	1,430,468,593		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	433,430,501	433,430,501		
21	Nuclear Production				
22	Hydraulic Production-Conventional	251,779,017	251,779,017		
23	Hydraulic Production-Pumped Storage				
24	Other Production	12,615,688	12,615,688		
25	Transmission	221,027,699	221,027,699		
26	Distribution	424,878,403	424,878,403		
27	Regional Transmission and Market Operation				
28	General	86,737,285	86,737,285		
29	TOTAL (Enter Total of lines 20 thru 28)	1,430,468,593	1,430,468,593		

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

Relocation reimbursements, Up and down costs and damage insurance claims $631,685.

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

Accumulated Provision for depreciation on Asset Retirement Obligation	$ (172,522)
Embedded removal in Accumulated Provision for Depreciation	(848,442)

	$(1,020,964)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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			49,451,102
5				
6	Subtotal Idaho Energy Resources Company			51,914,196
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41				
42	Total Cost of Account 123.1 $ 2,463,093		TOTAL	51,914,196

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	04/11/2008	End of 2007/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

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

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
		500		2
		2,462,594		3
4,022,911		53,474,013		4
				5
4,022,911		55,937,107		6
				7
				8
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4,022,911		55,937,107		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	04/11/2008	End of 2007/Q4

MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	15,173,831	17,267,629	Electric
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)			
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	12,191,263	12,737,352	
8	Transmission Plant (Estimated)	8,189,143	9,429,545	
9	Distribution Plant (Estimated)	15,527,757	18,595,934	
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	854,043	607,920	
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	36,762,206	41,370,751	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)	2,316,011	1,898,952	Electric
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	54,252,048	60,537,332	

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EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1	None					
2						
3						
4						
5						
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10						
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12						
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15						
16						
17						
18						
19						
20	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	04/11/2008	End of 2007/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21	None					
22						
23						
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49	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	04/11/2008	End of 2007/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Asset Retirement Obligations - IPUC	11,206,056	1,673,431	230	691,422	12,188,065
2	Order #29414 - OPUC Order #04-585					
3						
4	LT & ST Mark to Market	1,462,637	4,365,170	244	5,656,573	171,234
5						
6	Fin 48 Unfunded-Noncurrent-IPUC Order 29601		7,196,711	Various	44,264,451	-37,067,740
7						
8	Regulatory Unfunded Accumulated Deferred Income Tax	343,589,654	36,884,085	See Note	22,559,944	357,913,795
9						
10	PCA Deferral Idaho - IPUC order 30047		161,349,980	See Note	75,618,247	85,731,733
11	(amort period 6/08 thru 5/09)					
12						
13	Prior Year PCA - Idaho - IPUC order 30325		76,602,722	401	70,012,186	6,590,536
14	(amort period 6/07 thru 5/08)					
15						
16	Idaho - Demand Side Management - IPUC order	11,349,143		401	3,242,604	8,106,539
17	#27660 (amort period 7/98 thru 6/10)					
18						
19	Excess Power Deferral 06/07 - IPUC order		2,106,816			2,106,816
20	07-555					
21						
22	Excess Power Amortization - OPUC Order#06-070	6,670,347	2,684,150	254	6,361,893	2,992,604
23	(Capped at 10% per year until full amort)					
24						
25	Security Costs 2001-2002 - IPUC Order #28975	196,825		401	196,825	
26	(amort period 1/03 - 12/07)					
27						
28	Security Costs 2003 - IPUC Order #28975	137,588		401	68,794	68,794
29	(amort period 1/04 - 12/08)					
30						
31	Professional Fees - IPUC order #29505	21,246		407	21,246	
32	(Amort period 1/03 thru 12/07)					
33						
34	IPUC Grid West Loans - IPUC order #30157	932,177		401	186,435	745,742
35	(amort period 1/07 - 12/11)					
36						
37	OPUC Grid West Loans - OPUC Order #06-483	56,007	4,400			60,407
38						
39	FERC Grid West Expense	302,117				302,117
40	FERC Docket # AC03-78-000					
41						
42	Unfunded SFAS 106 Lia 30256 - IPUC Order #30256		17,031,607	228	9,025,198	8,006,409
43						
44	TOTAL	378,846,883	310,289,698		240,908,664	448,227,917

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	04/11/2008	End of 2007/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets	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	Excess Power Deferred - Oregon	2,889,117	87,806	254	2,976,923	
2	OPUC Order # 05-870					
3						
4	PS & I Coal Plant - Order #29904		257,301	401	21,442	235,859
5	(amort period 10/2007 thru 9/10)					
6	Minor items	33,969	45,519	various	4,481	75,007
7						
8						
9						
10						
11						
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43						
44	TOTAL	378,846,883	310,289,698		240,908,664	448,227,917

Schedule Page: 232 Line No.: 8 Column: d

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Account 282          $ (3,615,944)
Account 182           (18,944,000)
                     -------------
 Total               $(22,559,944)
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Schedule Page: 232 Line No.: 10 Column: d

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Account 182          $ (42,115,280)
Account 232            (33,502,967)
                     -------------
Total                  (75,618,247)
                     ==============
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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	04/11/2008	End of 2007/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Advance prepaid coal royalties	1,773,561		131	116,512	1,657,049
2						
3	Security plan	28,102,337	2,392,108	165, 426	4,574,015	25,920,430
4						
5	American Falls bond refinance	264,366		401	14,552	249,814
6	(amort period 4/00 thru 7/26)					
7						
8	Prepaid Credit Facility	430,723	386,177	431	176,868	640,032
9						
10	Company owned Life Insurance	5,952,711	810,350	131, 426	1,841,761	4,921,300
11						
12	American Falls water rights	18,842,991		401	1,042,008	17,800,983
13	(amort period 1/06 thru 12/25					
14						
15	Milner bond guarantee	11,700,000				11,700,000
16						
17	Southwest intertie project -	6,374,574	42,437			6,417,011
18	right of way costs					
19						
20	CSPP receivable	652,662		143	381,895	270,767
21						
22	American Falls - bond refinance	871,984		401	47,999	823,985
23	(35 year amortization)					
24						
25	Shelf Registration - 2008		144,517			144,517
26						
27	Transmission Deposit-PacifiCorp	1,078,850	1,892,125	131	616,875	2,354,100
28						
29	Prepaid Peoplesoft/Passport	95,586		401	44,243	51,343
30						
31	Adjustment to Unfunded Pension	46,181,245		182	46,181,245	
32						
33	Transmission - General Studies	342,200	5,731,573	various	6,073,773	
34						
35	06 Sweetwater Refi Costs	1,678,248	1,651,940	181, 186	3,330,188	
36	(Amort period 2-2007 to 7-2026)					
37						
38	Valmy Power Plant		1,128,524	various	867,551	260,973
39						
40	Minor Items & Job Orders (10)	46,896	206,513	various	243,530	9,879
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	124,388,934				73,222,183

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	12,175,361	6,920,941
4	Advances for Construction	9,211,519	10,171,998
5	Other Electric (See footnote)	13,118,190	16,363,768
6			
7	Other (See footnote)	68,217,184	57,716,499
8	TOTAL Electric (Enter Total of lines 2 thru 7)	102,722,254	91,173,206
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other Non Electric See footnote	14,416,632	14,873,945
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	117,138,886	106,047,151

Notes

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

(Note 1):	Beginning Balance	Ending Balance
Post Retiree Benefits-VEBA	$3,367,220	$4,056,405
Rate Case Disallowance	3,228,546	3,112,708
Other Employee's Long Term Deferred Compensation	2,538,014	2,590,724
IRS Interest Expense	-	2,148,245
FAS 123R - Stock Based Compensation	585,567	1,333,711
SFAS112 - Post Retirement Benefits	1,306,630	1,184,641
Provision For Rate Refunds	479,888	937,172
Non-VEBA Pension and Benefits	853,341	762,810
Linden Feeder Deposits	164,403	164,403
Delivery Accruals	5,692	129,130
Bonus Deferral	-	(56,182)
American Falls Falling Water Contract	407,373	-
City of Eagle	20,891	-
Restricted Stock Plan	160,625	-
Total Other Electric	$13,118,190	$16,363,768

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

(Other):	Beginning Balance	Ending Balance
FASB 109 Accounting	$41,825,257	$42,967,558
FAS 158 - Pension	11,263,649	3,815,138
FAS 158 - Postretirement Plan	10,603,161	6,616,914
Minimum Pension Liability	4,525,117	4,316,889
Total Other	$68,217,184	$57,716,499

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

(Other Non Electric):	Beginning Balance	Ending Balance
Senior Management Security Plan	$11,842,893	$12,554,517
Micron-CIAC	2,239,495	2,001,223
Meridian Gold Contributions	196,904	174,791
Start-up and Organization Costs	75,447	-
Seattle City Light-CIAC	16,542	324
Loss on Pioneer Land Write-down	45,351	45,351
Bridger Seirra Reserve-Legal Fees		97,739
Total Non Electric	$14,416,632	$14,873,945

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	04/11/2008	End of 2007/Q4

CAPITAL STOCKS (Account 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Account 201			
2	Common Stock registered on New York	50,000,000	2.50	
3	and Pacific Stock Exchange			
4	Total Common Stock	50,000,000	2.50	
5				
6	Account 204 - None			
7				
8				
9				
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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) 04/11/2008	Year/Period of Report End of 2007/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
39,150,812	97,877,030					2
						3
39,150,812	97,877,030					4
						5
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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	04/11/2008	End of 2007/Q4

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

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.
(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Account 208 - Donations received from stockholders	
2		
3	Account 209 - Reduction in par or stated value of Capital Stock	
4		
5	Account 210 - Gain on reacquired Capital Stock	
6		
7		
8	Account 211 - Miscellaneous paid-in Capital	
9		
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39		
40	TOTAL	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

CAPITAL STOCK EXPENSE (Account 214)

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

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Stock	2,096,925
2		
3		
4		
5		
6		
7		
8		
9		
10	Explanation of Changes during the year:	
11		
12		
13		
14		
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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	04/11/2008	End of 2007/Q4

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Account 221:		
2	First Mortgage Bonds:		
3	5.50% Series due 2033	70,000,000	728,701
4			36,400 D
5			
6	7.38% Series Due 2007	80,000,000	
7			
8	7.20% Series due 2009	80,000,000	572,246
9			
10	5.30% Series Due 2035	60,000,000	408,411 D
11			3,844,739
12			
13	6.60% Series due 2011	120,000,000	860,502
14			
15	4.25%Series due 2013	70,000,000	641,201
16			374,500 D
17			
18	4.75% Series due 2012	100,000,000	944,356
19			1,047,617 D
20			
21	6.00% Series due 2032	100,000,000	1,069,356
22			543,244 D
23			
24	5.875% Series due 2034	55,000,000	585,759
25			383,322 D
26			
27	5.50% Series due 2034	50,000,000	746,961 D
28			524,419
29			
30	6.30% Series due 2037)IPUC IPC-E-07-06		1,495,799
31	OPUC UF 4238 WPSC 2005-30-ES-7)		273,721 D
32			
33	TOTAL	987,045,000	19,666,627

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
05/01/03	04/01/33	05/01/03	03/31/33	70,000,000	3,850,000	3
						4
						5
12/1/00	12/01/07	12/01/00	12/01/07		5,439,510	6
						7
11/23/99	12/01/09	01/01/00	01/01/10	80,000,000	5,760,000	8
						9
08/26/05	08/26/35	08/26/05	08/26/35	60,000,000	3,180,000	10
						11
						12
03/02/01	03/02/11	03/02/01	03/02/11	120,000,000	7,920,000	13
						14
05/01/03	10/01/13	05/01/03	09/29/13	70,000,000	2,975,000	15
						16
						17
11/15/02	11/15/12	11/15/02	11/15/12	100,000,000	4,750,000	18
						19
						20
11/15/02	11/15/32	11/15/02	11/15/32	100,000,000	6,000,000	21
						22
						23
08/16/04	08/16/34	08/16/04	08/16/34	55,000,000	3,231,250	24
						25
						26
03/26/04	03/15/34	03/26/04	03/15/34	50,000,000	2,750,000	27
						28
						29
6/22/07	6/15/2037	6/22/07	6/15/2037	140,000,000	4,630,500	30
						31
						32
				1,145,981,364	58,097,082	33

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	04/11/2008	End of 2007/Q4

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	6.25% Series due 2037 (IPUC IPC-E-06-28		1,141,489
2	OPUC UF 4211 WPSC 20005-ES-4-27)		266,188 D
3			
4	Series 96B due 2026		
5			
6	Port of Morrow Variable due 2027	4,360,000	188,545
7			
8	Humboldt Variable due 2024	49,800,000	1,697,856
9			
10	Sweetwater Variable due 2026	116,300,000	820,043
11			471,252 D
12	Subtotal Account 221	955,460,000	19,666,627
13			
14	Account 224:		
15	Bond Guarantee - American Falls	19,885,000	
16			
17	REA Notes		
18			
19	Note Guarantee - Milner Dam	11,700,000	
20			
21	Subtotal Account 224	31,585,000	
22			
23	Account 222: Required Bonds		
24	Account 223: Advances for Associated Companies		
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	987,045,000	19,666,627

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
10/18/07	10/15/2037	10/18/07	10/15/2037	100,000,000	1,267,361	1
						2
						3
07/25/96	07/15/26	07/25/96	07/15/26		596	4
						5
05/17/00	02/01/27	05/17/00	02/01/27	4,360,000	175,605	6
						7
10/22/03	12/01/24	11/01/03	12/01/24	49,800,000	1,833,848	8
						9
10/3/06	7/15/26	10/3/06	7/15/2026	116,300,000	4,333,551	10
						11
				1,115,460,000	58,097,221	12
						13
						14
04/26/00	2/1/25			19,885,000		15
						16
					-139	17
						18
02/10/92				10,636,364		19
						20
				30,521,364	-139	21
						22
						23
						24
						25
						26
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						29
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						31
						32
				1,145,981,364	58,097,082	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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)	76,579,025
2		
3		
4	Taxable Income Not Reported on Books	
5	See Footnote	36,569,775
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	See Footnote	62,430,878
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15	See Footnote	18,405,712
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	See Footnote	5,200,269
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	27,101,941
28	Show Computation of Tax:	
29	Tenative Federal Tax @ 35%	9,485,679
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Schedule Page: 261 Line No.: 5 Column: b

004003-CONSTRUCTION ADV-252	2,977,340
004004-CIAC AS TAXABLE INC CLOSED TO PLANT	30,000,000
004005-AVOIDED COST INT CAP	6,539,451
004010-EMISSION ALLOWANCE-254.409-411	(13,440,132)
004013-CIAC AS TAXABLE INC IN ACCT 107	9,469,354
004020-ENGINEERING FEES-CLOSED TO PLANT	1,632,541
004021-ENGINEERING FEES-IN ACCT 107-FED ONLY	(12,267)
004501-ROYALTY INCOME BTL	100,000
004506-CIAC-MERIDIAN GOLD	(56,560)
004507-CIAC-MICRON-DRAM	(608,470)
004512-CIAC-SEATTLE CITY LIGHT	(41,482)
Total	**36,559,775**

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

Total Federal and State taxes deducted on books	34,697,263
005001-BAD DEBT EXPENSE	336,985
005008-GAIN/LOSS ON REACQUIRED DEBT-DEFERRED	504,035
005010-SFAS 112-POST-EMPLY BEN 182/253	(312,031)
005014-OVERACCRUED VACATION-ACCT 242	420,187
005017-INJURIES & DAMAGES	353,982
005019-DIRECTORS FEES DEF	287,447
005022-CAPITALIZED OVERHEADS	(12,000,000)
005023-PENSION ACCR TO 926200	2,919,438
005024-MEALS (50% NON-DEDUCTIBLE) CHRGD TO R.E.	500,000
005025-MILNER FALLING WATER - REV ACCRL	(714,918)
005027-AMORTIZATION OF ACCOUNT 114	(22,723)
005028-OREGON OPER PROPERTY TAX ADJ	(4,018)
005033-NONVEBA PEN&BEN-Acct 228	(231,565)
005035-PCA EXPENSE DEFERRAL	(97,251,403)
005043-AMERICAN FALLS - FALLING WATER CONTRACT-FT	1,042,009
005047-OTHER EMPLOYEE'S LT DEFERRED COMP-228	134,829
005050-186-BAD DEBT RESERVE-FINANCING PRGMS	(1,706)
005051-PUC ORDER 29505 - PROFESSIONAL FEES	21,246
005052-AMORTIZATION OF ACCOUNT 181	92,448
005053-FAS 123R-STOCK BASED COMPENSATION	1,408,339
005054-IPUC GRID WEST LOANS-ACCT 182	186,435
005055-OPUC GRID WEST LOANS-ACCT 182	(4,400)
005057-INTERVENOR FUNDING ORDERS-ACCT 182	(52,604)
005058-FIXED COST ADJUSTMENT (FCA)-ACCT 182	2,145,403
005059-PS & I COSTS-COAL & CHP PLANTS-WRITE OFF	(258,262)
005501-SEC PLAN-NET INS COSTS	(254,430)
005503-128-EDC-UNRLZD GN/LS FRM RABBI TRUST	20,683
005504-NONDEDUCTIBLE POLITICAL EXP-426.4	895,713
005505-SEC PLAN-BENEFIT ACCR	1,820,242
005510-FINES & PENALTIES-OPERATING-CHRGD TO R.E.	669,811
005516-NONDEDUCTIBLE POLITICAL EXP-O&M ACCTS	100,000
005531-RATE CASE DISALLOWANCES-REVERSE AMORT	(296,299)
005532-DELIVERY ACCRUALS-253.550	158,786
005536-VEBA INCOME TAXES	8,200
005537-BRIDGER SIERRA RESERVE-LEGAL FEE'S-228.4	250,000
Total	(62,430,878)

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.: 15 Column: b

007009-PROVISION FOR RATE REFUNDS-ACCT 229	(1,169,674)
007501-REVERSE EQUITY EARNINGS OF SUBSIDIARIES	4,022,911
007502-ALLOWANCE FOR OFUDC	5,995,175
007503-ALLOWANCE FOR BFUDC	7,597,141
007509-SECURITY PLAN-INSURANCE PROCEEDS	1,202,946
007514-COLI-INSURANCE PROCEEDS	368,625
007518-IRS INTEREST INCOME	388,588
Total	18,405,712

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

008001-VEBA-POST RET BNFTS-TRUST-ACCT 228	(1,762,847)
008009-DEPR FOR TAX GT OR LT BOOK	(5,258,723)
008016-VEBA-POST RET BNFTS-TRUST-MEDICARE PART D	803,000
008020-CONSERVATION PROGRAMS	(3,242,604)
008025-MANUFACTURING DEDUCTION	1,116,887
008027-NEVADA OPERATING PROPERTY TAX ADJ	7,262
008034-REMOVAL COSTS	10,819,971
008035-REPAIR ALLOWANCE	7,000,000
008038-OREGON EXCESS PWR SUPPLY COSTS	(3,571,969)
008039-ST TAX-NOT DEDUCTED ON PRIOR RETURN	207,179
008041-AM FALLS - UNAMORTIZED DEBT EXP	(47,999)
008042-GAIN/LOSS ON REACQUIRED DEBT-FT	(707,798)
008059-SFTWR COSTS-MISC-107-FED ONLY	1,000,000
008072-INTANGIBLE ASSET-LABOR DEDUCT-107-FED ONLY	2,700,000
008074-INCREMENTAL SECURITY COSTS DEDUCTED	(265,619)
008077-PP INS & OTR EXP (1 YR OR LESS)-165	52,662
008501-COLI-TAX ADJ FROM BOOKS	(1,005,148)
008504-OREGON NONOP PROPERTY TAX ADJUST	(1,218)
008508-DEPR ADJ - NONOP - OTHER PROPERTY - NEW	3,887
008702-FAS123R RESTRICTED STOCK DIVIDENDS	354,425
0NI0016-DIV PAID DED PUB UTIL	300,000
IRS INTEREST EXPENSE	1,008,190
STATE INCOME TAX DEDUCTED ON FEDERAL RETURN	(4,309,269)
Total	5,200,269

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	Federal:					
2	Income	24,271,360		-21,881,577	5,165,847	
3	Social Security - (FOAB)	381,573		10,995,817	10,960,220	
4	Unemployment	39,547		126,114	122,638	
5	Subtotal Federal	24,692,480		-10,759,646	16,248,705	
6						
7	State of Idaho:					
8	Property	4,744,361	75	10,029,025	9,053,722	
9	Income	7,546,331		-14,226,720	-5,218,719	
10	KWH	92,992		1,490,284	1,282,559	
11	Unemployment	18,600		231,339	230,218	
12	Regulatory Commission			1,599,171	1,599,171	
13	Business License - Sho Ban		150	150	150	
14	Subtotal Idaho	12,402,284	225	-876,751	6,947,101	
15						
16	State of Oregon					
17	Property		1,003,085	2,010,673	2,014,692	
18	Non-Operating Property		1,937	2,655	1,437	
19	Income	928,546		-924,316	71,171	
20	Regulatory Commission			109,195	109,195	
21	Unemployment	1,474		16,603	17,178	
22	Franchise	126,401		505,272	506,460	
23	Subtotal Oregon	1,056,421	1,005,022	1,720,082	2,720,133	
24						
25	State of Montana:					
26	Property	49,639		93,297	96,518	
27	Subtotal Montana	49,639		93,297	96,518	
28						
29	State of Nevada:					
30	Property		411,955	870,048	877,309	
31	Business Tax			100	100	
32	Subtotal Nevada		411,955	870,148	877,409	
33						
34	State of Wyoming					
35	Corporate License			2,911	2,911	
36	Property	514,075		956,616	992,383	
37	Subtotal Wyoming	514,075		959,527	995,294	
38	Other States Income	1,510,858		-1,510,694	1,515	
39	Payroll Adjustment			-11,369,873		
40						
41	TOTAL	40,225,757	1,417,202	-20,873,910	27,886,675	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
-2,776,064		6,214,288		-29,821,538	1,725,673	2
417,170		10,995,817				3
43,023		126,114				4
-2,315,871		17,336,219		-29,821,538	1,725,673	5
						6
						7
5,719,815	225	9,995,700			33,325	8
-1,461,670		-6,449,912		-8,119,462	342,654	9
300,717		1,490,284				10
19,721		231,339				11
		1,599,171				12
	150	150				13
4,578,583	375	6,866,732		-8,119,462	375,979	14
						15
						16
	1,007,104	2,008,018			2,655	17
	719	2,655				18
-66,941		4,774		-946,512	17,422	19
		109,195				20
899		16,603				21
125,213		505,272				22
59,171	1,007,823	2,646,517		-946,512	20,077	23
						24
						25
46,418		93,297				26
46,418		93,297				27
						28
						29
	419,217	870,048				30
		100				31
	419,217	870,148				32
						33
						34
		2,911				35
478,308		956,616				36
478,308		959,527				37
-1,351		-127,413		-1,389,090	5,809	38
		-11,369,873				39
						40
2,845,258	1,427,415	17,275,154		-40,276,602	2,127,538	41

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

Account	409.2	$1,749,032
	234	(23,359)
Total		$1,725,673

Schedule Page: 262 Line No.: 8 Column: l

Account 408.2 $ 33,325

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

Account	409.2	$ 346,857
	234	(4,203)
Total		$ 342,654

Schedule Page: 262 Line No.: 17 Column: l

Account 408.2 $ 2,655

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

Account	409.2	$ 17,636
	234	(214)
Total		$ 17,422

Schedule Page: 262 Line No.: 38 Column: l

Account	409.2	$ 5,880
	234	(71)
Total		$ 5,809

Schedule Page: 262 Line No.: 40 Column: i

This footnote is for the total of Column I. The total of column I should total back to the sum on lines 14, 15 & 16 on page 114 column C. For the year 2007 this cross-check will not work as the total on lines 14-16 on page 114 is $3,586,298 higher. This amount represents an amount booked for the accounting of Fin #48. When FIN #48 is booked it does use account 409.1 however it does not use account 236. Therefore it will show up on page 114 but not on pages 262 and 263.

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ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%	1,232,965				152,178	
4	7%						
5	10%	32,350,078				1,875,097	
6	11%	1,374,592				27,085	
7	Other State	34,155,507	411.4	5,465,795	411.4	1,523,866	
8	TOTAL	69,113,142		5,465,795		3,578,226	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Line 6 Col A 11%						
11							
12	State of Idaho	34,155,507	411.4	5,465,795	411.4	1,523,866	
13							
14							
15							
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ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
1,080,787	8.10		3
			4
30,474,981	17.25		5
1,347,507	50.75		6
38,097,436	22.41		7
71,000,711			8
			9
			10
			11
38,097,436			12
			13
			14
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OTHER DEFFERED CREDITS (Account 253)

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

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Bureau of Land Mngt Rents/ROW	5,129,477	107	758,017	804,524	5,175,984
2						
3	Point to Point Transmission Study	509,930	232,253	2,890,341	6,642,869	4,262,458
4						
5	FTV	5,066,666	454	400,639	1,000,000	5,666,027
6						
7	Linden Feeder	420,523				420,523
8						
9	SWIP Deposit	1,000,000			500,000	1,500,000
10						
11	City of Eagle	53,437	232	186,181	132,744	
12						
13	Fin 48		Various	13,896,564	4,726,583	-9,169,981
14						
15	Fin 48 Interest		431	1,113,132	311,082	-802,050
16						
17	Sho Ban Trans ROW	315,000	242	7,500		307,500
18						
19	Delivery Accruals	19,308	253	693,251	932,375	258,432
20						
21	Customer Level Pay	2,028,970	142	1,959,997	1,757,662	1,826,635
22						
23	US Airforce Photovoltaic Generator	244,147			44,591	288,738
24						
25	Security Plan	24,675,204	228	29,861,039	5,185,835	
26						
27	Milner Falling Water	3,721,057			348,719	4,069,776
28						
29	Postretirement Benefits	3,342,191	926	312,031		3,030,160
30						
31	Directors Deferred Compensation	3,716,793	232	289,911	577,359	4,004,241
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	50,242,703		52,368,603	22,964,343	20,838,443

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	04/11/2008	End of 2007/Q4

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
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	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities			
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)			
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)			
18	Classification of TOTAL			
19	Federal Income Tax			
20	State Income Tax			
21	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) 04/11/2008	Year/Period of Report End of 2007/Q4

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (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.
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
							15
							16
							17
							18
							19
							20
							21

NOTES (Continued)

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	04/11/2008	End of 2007/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)	Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	230,117,962	5,401,035	8,426,116
3	Gas			
4	Other			
5	TOTAL (Enter Total of lines 2 thru 4)	230,117,962	5,401,035	8,426,116
6	Non-Operating Property	243,443		
7	Other - FASB 109	343,589,653		
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	573,951,058	5,401,035	8,426,116
10	Classification of TOTAL			
11	Federal Income Tax	485,101,346	5,375,340	8,426,116
12	State Income Tax	88,849,712	25,695	
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) 04/11/2008	Year/Period of Report End of 2007/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
						227,092,881	2
							3
							4
						227,092,881	5
1,520	385					244,578	6
		182	44,393,748	182	9,094,188	308,290,093	7
							8
1,520	385		44,393,748		9,094,188	535,627,552	9
							10
1,275	323		37,125,106		8,213,755	453,140,171	11
245	62		7,268,642		880,433	82,487,381	12
							13

NOTES (Continued)

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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	04/11/2008	2007/Q4

FOOTNOTE DATA

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

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

		2,007	Changes during Year				Adjustments Debits		Adjustments Credits		2,007
Line No.	Account (a)	Beginning Balance b	DR to 410.1 c	CR to 411.1 d	DR to 410.2 e	CR to 411.2 f	Acct. CR. g	Amt h	Acct. dr. i	Amount j	Ending Balance k
Line 2:	Accelerated Depreciation	219,454,281	3,898,285	8,235,357							215,117,209
	Intangible Asset-Labor Deduction	11,327,736	924,761								12,252,496
	FERC Jurisdictional	7,818,502									7,818,502
	N. Valmy	733,766		76,500							657,266
	Bridger	222,457		102,400							120,057
	Engineering Fees in Acct 107	(35,263)	4,293	11,859							(42,828)
	Misc Software Develop Costs	(2,565,535)	3,443,205								877,670
	Taxable CIAC in CWIP Bal.	(6,837,982)	(2,869,509)	-							(9,707,491)
	TOTAL Line 2	230,117,961	5,401,035	8,426,116	-	0.00		0.00		0.00	227,092,881

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Other Electric -- See Note	13,498,365	36,645,101	2,223,304
4				
5				
6				
7				
8	Other -- See Note	18,896,235		
9	TOTAL Electric (Total of lines 3 thru 8)	32,394,600	36,645,101	2,223,304
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other -- See Note	352,332		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	32,746,932	36,645,101	2,223,304
20	Classification of TOTAL			
21	Federal Income Tax	27,443,632	30,739,892	1,838,745
22	State Income Tax	5,303,300	5,905,209	384,559
23	Local Income Tax			

NOTES

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	04/11/2008	End of 2007/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					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
[redacted]							1
							2
						47,920,162	3
							4
							5
							6
							7
			11,586,798			7,309,437	8
			11,586,798			55,229,599	9
[redacted]							10
							11
							12
							13
							14
							15
							16
							17
143,833	40,278					455,887	18
143,833	40,278		11,586,798			55,685,486	19
[redacted]							20
120,655	33,787		9,719,643			46,712,004	21
23,178	6,491		1,867,155			8,973,482	22
							23

NOTES (Continued)

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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	04/11/2008	2007/Q4

FOOTNOTE DATA

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

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

Line No.	Account (a)	2,007 Beginning Balance b	Changes during Year DR to 410.1 c	CR to 411.1 d	DR to 410.2 e	CR to 411.2 f	Adjustments Debits Acct. cr g	Amount h	Adjustments Credits Acct. dr i	Amount j	2,007 Ending Balance k
Line 3:	PCA Expense Deferral	4,646,703	36,956,236	(1,064,201)							42,667,139
	Conservation Programs	4,436,949	0	1,267,697							3,169,251
	Oregon Excess Power Costs	3,737,272	(444,523)	951,938							2,340,811
	IPUC Grid West Loans	364,435	0	72,887							291,548
	Loss on Reacquired Debt	197,052	0	197,053							0
	Incremental Security Costs	130,739	0	103,844							26,895
	FERC Grid West Expense	118,113	0	0							118,113
	OPUC Grid West Loans	21,896	1,720								23,616
	Prof Fees - IPUC Order 29505	8,306	0	8,306							-
	Intervenor Funding Orders	0	20,566	0							20,566
	Fixed Cost Adjustment	0	0	838,745							(838,745)
	PS & I Costs - Coal & CHP Plants-Write Off	0	111,102	10,135							100,968
	FERC order 144a	(163,100)		(163,100)							-
	TOTAL Line 3	13,498,365	36,645,101	2,223,304	-	-		-		-	47,920,162

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

Line No.	Account (a)	b	c	d	e	f	g	h	i	j	k
Line 8:	FAS 158 - Pension	11,263,649					190	7,448,512	190	-	3,815,138
	FAS 158 - Postretirement Plan	6,790,908					186/190	3,660,803	186/190	-	3,130,106
	Unrealized gains on Mkt Securities	841,677					219	477,483	219	-	364,194
	TOTAL Line 8	18,896,235	-	-	-	-		11,586,798		-	7,309,437

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

Line No.	Account (a)	b	c	d	e	f	g	h	i	j	k
Line 18:	Advance Coal Royalties	287,571			0	39,802					247,769
	IRS Interest Income	0			151,918	0					151,918
	Oregon Non-Op Prop Tax Adj	757			0	476					281
	Unrealized Gain/Loss From Rabbit Trust	64,004			(8,086)	0					55,918
	TOTAL Line 18	352,332	-	-	143,833	40,278		-		-	455,887

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Market to Market Short Term		175	508,046	1,061,088	553,042
2						
3	Demand Side Management Rider 29026	5,934,462	various	16,861,669	12,410,280	1,483,073
4						
5	Demand Side Management Rider OR	393,731	various	649,458	665,953	410,226
6						
7	FAS 133 - Market to Market				33,160	33,160
8						
9	Other Deferred Credit - PCA	(11,851,702)	182	1,933,284	13,784,986	
10						
11	Fixed Cost Adjustment - 30267		407,431	111,491	2,256,894	2,145,403
12						
13	BPA Credit-Residential - Idaho	1,110,658	131,142,400	11,038,319	9,942,616	14,955
14						
15	BPA Credit-Residential - Oregon	63,368	131,142,400	659,471	417,418	-178,685
16						
17	BPA Credit-Farm - Idaho	923,749	131,142	12,077	74,246	985,918
18						
19	BPA Credit-Farm - Oregon	26,458	142	302	2,382	28,538
20						
21	Emission Sales Interest - Idaho	27,025,013	182	87,552,992	60,527,980	1
22						
23	Emission Sales Interest - Oregon	4,118,000	182	7,313,230	3,195,230	
24						
25	Unfunded Accumulated Deferred Income Tax	41,825,257			1,142,301	42,967,558
26						
27	Asset Retirement Oblication - Removal Cost	156,162,048	108	1,839,118	990,675	155,313,605
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	225,731,042		128,479,457	106,505,209	203,756,794

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	04/11/2008	End of 2007/Q4

ELECTRIC OPERATING REVENUES (Account 400)

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

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	308,207,698	299,593,554
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	256,206,389	231,430,314
5	Large (or Ind.) (See Instr. 4)	101,409,337	102,958,015
6	(444) Public Street and Highway Lighting	2,479,808	2,392,957
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	668,303,232	636,374,840
11	(447) Sales for Resale	154,948,157	260,717,491
12	TOTAL Sales of Electricity	823,251,389	897,092,331
13	(Less) (449.1) Provision for Rate Refunds	1,075,534	1,211,251
14	TOTAL Revenues Net of Prov. for Refunds	822,175,855	895,881,080
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	4,050,513	5,424,893
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	19,035,198	16,858,178
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	13,910,578	12,454,460
22	(456.1) Revenues from Transmission of Electricity of Others	16,229,091	
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	53,225,380	34,737,531
27	TOTAL Electric Operating Revenues	875,401,235	930,618,611

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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ELECTRIC OPERATING REVENUES (Account 400)

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

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
5,227,166	5,067,767	397,286	387,707	2
				3
5,831,537	5,368,218	78,670	76,343	4
3,453,633	3,475,157	126	130	5
29,489	28,172	1,012	789	6
				7
				8
				9
14,541,825	13,939,314	477,094	464,969	10
2,743,647	5,820,823			11
17,285,472	19,760,137	477,094	464,969	12
				13
17,285,472	19,760,137	477,094	464,969	14

Line 12, column (b) includes $ 4,992,047 of unbilled revenues.

Line 12, column (d) includes 14,715 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) 04/11/2008	Year/Period of Report End of 2007/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	440 - Residential Sales:					
2	01 - Residential	5,212,066	305,027,941	397,139	13,124	0.0585
3	04 - Residential - EW	966	54,767	61	15,836	0.0567
4	05 - Residential - TOD	1,290	74,392	86	15,000	0.0577
5	15 - Dusk to dawn lighting	2,496	440,707			0.1766
6	Unbilled Revenues	10,348	2,609,891			0.2522
7	Total 440	5,227,166	308,207,698	397,286	13,157	0.0590
8						
9	442-Commercial & Industrial Sales					
10	07 - General service	205,731	14,963,806	32,594	6,312	0.0727
11	09 - General service	414,207	14,543,557	145	2,856,600	0.0351
12	09 - General service	3,266,478	135,415,311	26,733	122,189	0.0415
13	09 - General service	2,448	86,175	2	1,224,000	0.0352
14	15 - Dusk to Dawn Light	3,885	606,368			0.1561
15	19 - Uniform rate contracts	2,186,000	67,007,083	117	18,683,761	0.0307
16	19 - Uniform rate contracts	8,483	289,543	1	8,483,000	0.0341
17	19 - Uniform rate contracts	171,591	4,832,098	5	34,318,200	0.0282
18	24 - Irrigation Pumping	1,906,104	87,854,039	17,967	106,089	0.0461
19	25 - Irrigation Pumping -Time of	17,557	823,734	75	234,093	0.0469
20	40 - General service	14,075	752,826	1,154	12,197	0.0535
21	Commercial & Industrial & Unbill	1,088,611	30,441,186	3	362,870,333	0.0280
22	Total 442	9,285,170	357,615,726	78,796	117,838	0.0385
23						
24	444 - Public Street Lighting:					
25	40 - General service	2,677	143,716	643	4,163	0.0537
26	41 - Street lighting	21,782	2,165,079	149	146,188	0.0994
27	42 - Traffic control lighting	5,030	171,013	220	22,864	0.0340
28	Total 444	29,489	2,479,808	1,012	29,139	0.0841
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	14,527,110	663,311,185	477,094	30,449	0.0457
42	Total Unbilled Rev.(See Instr. 6)	14,715	4,992,047	0	0	0.3392
43	TOTAL	14,541,825	668,303,232	477,094	30,480	0.0460

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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	9.425	9.425	0.000
2	Raft River Rural Electric	RQ	V6-44	0.000	0.000	0.000
3	City of Weiser	RQ	V6-53	0.000	0.000	0.000
4						
5	Arizona Public Service Co.	OS	WSPP	0.000	0.000	0.000
6	Arizona Public Service Co.	SF	WSPP	0.000	0.000	0.000
7	Avista Corp. - WWP Div.	OS	WSPP	0.000	0.000	0.000
8	Avista Corp. - WWP Div.	SF	WSPP	0.000	0.000	0.000
9	Avista Corp. - WWP Div.	SF	V6-60	0.000	0.000	0.000
10	Avista Energy, Inc.	OS	WSPP	0.000	0.000	0.000
11	Avista Energy, Inc.	OS	WSPP	0.000	0.000	0.000
12	Avista Energy, Inc.	SF	WSPP	0.000	0.000	0.000
13	Barclays Bank PLC	SF	WSPP	0.000	0.000	0.000
14	Bear Energy LP	SF	WSPP	0.000	0.000	0.000
	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	04/11/2008	End of 2007/Q4

SALES FOR RESALE (Account 447) (Continued)

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

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

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

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

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

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

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

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

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
57,422	493,689	1,169,385	6,000	1,669,074	1
			315,068	315,068	2
14		232	-13,433	-13,201	3
					4
85		7,225		7,225	5
11,282		428,869		428,869	6
400		22,000		22,000	7
15,630		768,145		768,145	8
			200	200	9
66,560		3,563,480		3,563,480	10
			9,235	9,235	11
94,909		4,848,857		4,848,857	12
61,812		2,734,089		2,734,089	13
20,400		1,187,850		1,187,850	14
57,436	493,689	1,169,617	307,635	1,970,941	
2,686,211	0	143,885,041	9,092,175	152,977,216	
2,743,647	**493,689**	**145,054,658**	**9,399,810**	**154,948,157**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Benton County PUD	SF	WSPP	0.000	0.000	0.000
2	Black Hills Power Inc.	OS	WSPP	0.000	0.000	0.000
3	Black Hills Power Inc.	OS	WSPP	0.000	0.000	0.000
4	Black Hills Power Inc.	SF	WSPP	0.000	0.000	0.000
5	Bonneville Power Administration	OS	WSPP	0.000	0.000	0.000
6	Bonneville Power Administration	SF	WSPP	0.000	0.000	0.000
7	BP Energy Company	SF	WSPP	0.000	0.000	0.000
8	Burbank, City of	OS	WSPP	0.000	0.000	0.000
9	Calpine Energy Services, L.P.	SF	WSPP	0.000	0.000	0.000
10	Cargill Power Markets LLC	OS	WSPP	0.000	0.000	0.000
11	Cargill Power Markets LLC	OS	WSPP	0.000	0.000	0.000
12	Cargill Power Markets LLC	SF	WSPP	0.000	0.000	0.000
13	Chelan Co PUD	SF	WSPP	0.000	0.000	0.000
14	Citigroup Energy Inc.	SF	WSPP	0.000	0.000	0.000
	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	04/11/2008	End of 2007/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
1,495		41,800		41,800	1
			939	939	2
330		19,220		19,220	3
10,735		504,579		504,579	4
3,447		174,695		174,695	5
47,610		2,235,252		2,235,252	6
190,454		10,733,667		10,733,667	7
93		7,161		7,161	8
594		26,170		26,170	9
			1,360,435	1,360,435	10
12,532		780,204		780,204	11
142,605		8,160,168		8,160,168	12
526		18,195		18,195	13
128,275		6,848,757		6,848,757	14
57,436	493,689	1,169,617	307,635	1,970,941	
2,686,211	0	143,885,041	9,092,175	152,977,216	
2,743,647	**493,689**	**145,054,658**	**9,399,810**	**154,948,157**	

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	04/11/2008	End of 2007/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Clatskanie PUD	SF	WSPP	0.000	0.000	0.000
2	Conoco Phillips Company	OS	WSPP	0.000	0.000	0.000
3	Conoco Phillips Company	SF	WSPP	0.000	0.000	0.000
4	Constellation Energy Commodities Gr	SF	WSPP	0.000	0.000	0.000
5	Coral Power, LLC	OS	WSPP	0.000	0.000	0.000
6	Coral Power, LLC	OS	WSPP	0.000	0.000	0.000
7	Coral Power, LLC	OS	WSPP	0.000	0.000	0.000
8	Coral Power, LLC	SF	WSPP	0.000	0.000	0.000
9	Credit Suisse Energy LLC	SF	WSPP	0.000	0.000	0.000
10	DB Energy Trading, LLC	SF	WSPP	0.000	0.000	0.000
11	Douglas County PUD	SF	WSPP	0.000	0.000	0.000
12	Energy Authority, The	SF	WSPP	0.000	0.000	0.000
13	Eugene Water & Electric Board	SF	WSPP	0.000	0.000	0.000
14	Fortis Energy Marketing & Trading G	SF	WSPP	0.000	0.000	0.000
	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	04/11/2008	End of 2007/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
792		40,736		40,736	1
			213	213	2
9,159		567,094		567,094	3
75,251		5,391,395		5,391,395	4
4,057		143,921		143,921	5
			5,306	5,306	6
27,702		1,617,998		1,617,998	7
121,537		6,281,368		6,281,368	8
60,000		3,596,700		3,596,700	9
29,475		1,476,256		1,476,256	10
34					11
102					12
5,852		300,894		300,894	13
29,800		1,957,700		1,957,700	14
57,436	493,689	1,169,617	307,635	1,970,941	
2,686,211	0	143,885,041	9,092,175	152,977,216	
2,743,647	**493,689**	**145,054,658**	**9,399,810**	**154,948,157**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Franklin County P.U.D.	SF	WSPP	0.000	0.000	0.000
2	Grant County P.U.D.	SF	WSPP	0.000	0.000	0.000
3	Grays Harbor PUD	OS	WSPP	0.000	0.000	0.000
4	Grays Harbor PUD	SF	WSPP	0.000	0.000	0.000
5	Highland Energy LLC	SF	WSPP	0.000	0.000	0.000
6	J. Aron & Company	SF	WSPP	0.000	0.000	0.000
7	Lehman Brothers Commodity Services,	SF	WSPP	0.000	0.000	0.000
8	Morgan Stanley Capital Group Inc.	OS	WSPP	0.000	0.000	0.000
9	Morgan Stanley Capital Group Inc.	OS	WSPP	0.000	0.000	0.000
10	Morgan Stanley Capital Group Inc.	SF	WSPP	0.000	0.000	0.000
11	Northern California Power Agency	OS	WSPP	0.000	0.000	0.000
12	Northern California Power Agency	OS	WSPP	0.000	0.000	0.000
13	Northern California Power Agency	SF	WSPP	0.000	0.000	0.000
14	NorthWestern Energy	IF	147	0.000	0.000	0.000
	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	04/11/2008	End of 2007/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
240		6,000		6,000	1
846		23,582		23,582	2
25		2,125		2,125	3
166					4
6,200		366,140		366,140	5
50,400		2,503,322		2,503,322	6
8,200		408,372		408,372	7
			41,897	41,897	8
1,463		91,847		91,847	9
170,604		11,050,822		11,050,822	10
867		56,766		56,766	11
1,121		79,914		79,914	12
807		37,714		37,714	13
68,878		3,688,463		3,688,463	14
57,436	493,689	1,169,617	307,635	1,970,941	
2,686,211	0	143,885,041	9,092,175	152,977,216	
2,743,647	**493,689**	**145,054,658**	**9,399,810**	**154,948,157**	

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	04/11/2008	End of 2007/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	NorthWestern Energy	SF	WSPP	0.000	0.000	0.000
2	NorthWestern Energy	IF	147	0.000	0.000	0.000
3	Okanogan County P.U.D.	SF	WSPP	0.000	0.000	0.000
4	Pacific Northwest Generating Cooper	SF	WSPP	0.000	0.000	0.000
5	PacifiCorp Inc.	OS	WSPP	0.000	0.000	0.000
6	PacifiCorp Inc.	OS	WSPP	0.000	0.000	0.000
7	PacifiCorp Inc.	SF	T-7	0.000	0.000	0.000
8	PacifiCorp Inc.	SF	WSPP	0.000	0.000	0.000
9	PacifiCorp Inc.	SF	V6-13	0.000	0.000	0.000
10	Portland General Electric Company	OS	WSPP	0.000	0.000	0.000
11	Portland General Electric Company	OS	WSPP	0.000	0.000	0.000
12	Portland General Electric Company	SF	WSPP	0.000	0.000	0.000
13	Portland General Electric Company	SF	V6-54	0.000	0.000	0.000
14	Powerex Corp.	OS	WSPP	0.000	0.000	0.000
	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) 04/11/2008	Year/Period of Report End of 2007/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
100		10,000		10,000	1
			3,965,340	3,965,340	2
37		1,898		1,898	3
1,187		47,402		47,402	4
			484,639	484,639	5
1,727		100,701		100,701	6
178		9,973		9,973	7
190,002		9,413,086		9,413,086	8
			425	425	9
			13,990	13,990	10
1,798		96,185		96,185	11
77,871		3,297,888		3,297,888	12
			1,700	1,700	13
			1,788,154	1,788,154	14
57,436	493,689	1,169,617	307,635	1,970,941	
2,686,211	0	143,885,041	9,092,175	152,977,216	
2,743,647	**493,689**	**145,054,658**	**9,399,810**	**154,948,157**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Powerex Corp.	OS	WSPP	0.000	0.000	0.000
2	Powerex Corp.	SF	WSPP	0.000	0.000	0.000
3	PPL EnergyPlus, LLC	OS	WSPP	0.000	0.000	0.000
4	PPL EnergyPlus, LLC	SF	WSPP	0.000	0.000	0.000
5	PPL Montana, LLC	OS	WSPP	0.000	0.000	0.000
6	PPL Montana, LLC	OS	WSPP	0.000	0.000	0.000
7	PPL Montana, LLC	OS	WSPP	0.000	0.000	0.000
8	PPL Montana, LLC	SF	WSPP	0.000	0.000	0.000
9	PPL Montana, LLC	SF	V6-57	0.000	0.000	0.000
10	PPM Energy, Inc.	OS	WSPP	0.000	0.000	0.000
11	PPM Energy, Inc.	SF	WSPP	0.000	0.000	0.000
12	Public Service Co. of Colorado	SF	WSPP	0.000	0.000	0.000
13	Public Service Company of New Mexic	SF	WSPP	0.000	0.000	0.000
14	Puget Sound Energy, Inc.	OS	WSPP	0.000	0.000	0.000
	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) 04/11/2008	Year/Period of Report End of 2007/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
2,935		132,770		132,770	1
142,125		6,081,785		6,081,785	2
			306	306	3
223		8,155		8,155	4
35		385		385	5
			13,243	13,243	6
1,010		77,290		77,290	7
14,979		659,070		659,070	8
			46,286	46,286	9
			8,229	8,229	10
176,209		9,397,452		9,397,452	11
2,567		116,173		116,173	12
1,665		66,700		66,700	13
1,325		64,850		64,850	14
57,436	493,689	1,169,617	307,635	1,970,941	
2,686,211	0	143,885,041	9,092,175	152,977,216	
2,743,647	**493,689**	**145,054,658**	**9,399,810**	**154,948,157**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Puget Sound Energy, Inc.	SF	T-7	0.000	0.000	0.000
2	Puget Sound Energy, Inc.	SF	WSPP	0.000	0.000	0.000
3	Rainbow Energy Marketing Corporatio	OS	WSPP	0.000	0.000	0.000
4	Rainbow Energy Marketing Corporatio	OS	WSPP	0.000	0.000	0.000
5	Rainbow Energy Marketing Corporatio	SF	WSPP	0.000	0.000	0.000
6	Salt River Project	OS	WSPP	0.000	0.000	0.000
7	Salt River Project	SF	WSPP	0.000	0.000	0.000
8	Seattle City Light	SF	WSPP	0.000	0.000	0.000
9	Sempra Energy Trading Corporation	OS	WSPP	0.000	0.000	0.000
10	Sempra Energy Trading Corporation	OS	WSPP	0.000	0.000	0.000
11	Sempra Energy Trading Corporation	SF	WSPP	0.000	0.000	0.000
12	Sempra Energy Trading LLC	SF	WSPP	0.000	0.000	0.000
13	Sierra Pacific Power Company	OS	WSPP	0.000	0.000	0.000
14	Sierra Pacific Power Company	OS	WSPP	0.000	0.000	0.000
	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) 04/11/2008	Year/Period of Report End of 2007/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
13		750		750	1
59,125		2,859,917		2,859,917	2
			103,415	103,415	3
283		15,865		15,865	4
16,400		732,450		732,450	5
200		18,000		18,000	6
158		11,754		11,754	7
22,289		961,975		961,975	8
12,105		695,327		695,327	9
			96,957	96,957	10
218,629		12,950,731		12,950,731	11
41,800		2,607,400		2,607,400	12
			1,151,266	1,151,266	13
33		1,320		1,320	14
57,436	493,689	1,169,617	307,635	1,970,941	
2,686,211	0	143,885,041	9,092,175	152,977,216	
2,743,647	**493,689**	**145,054,658**	**9,399,810**	**154,948,157**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW): Average Monthly NCP Demand (e)	Actual Demand (MW): Average Monthly CP Demand (f)
1	Sierra Pacific Power Company	SF	T-7	0.000	0.000	0.000
2	Sierra Pacific Power Company	SF	WSPP	0.000	0.000	0.000
3	Snohomish County PUD	OS	WSPP	0.000	0.000	0.000
4	Snohomish County PUD	SF	WSPP	0.000	0.000	0.000
5	Southern California Edison	SF	WSPP	0.000	0.000	0.000
6	SUEZ Energy Marketing NA, Inc.	SF	WSPP	0.000	0.000	0.000
7	Tacoma Power	SF	WSPP	0.000	0.000	0.000
8	TransAlta Energy Marketing (U.S.)	SF	WSPP	0.000	0.000	0.000
9	Tri-State Generation and Transmissi	OS	WSPP	0.000	0.000	0.000
10	Tucson Electric Power Company	SF	WSPP	0.000	0.000	0.000
11	UBS AG, London Branch	SF	WSPP	0.000	0.000	0.000
12	Utah Associated Municipal Power Sys	OS	WSPP	0.000	0.000	0.000
13	Western Area Power Administration	SF	WSPP	0.000	0.000	0.000
14	LESS BAD DEBT WRITE-OFF			0.000	0.000	0.000
	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	04/11/2008	End of 2007/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
21		1,209		1,209	1
6		408		408	2
50		3,900		3,900	3
16,961		658,444		658,444	4
255		13,417		13,417	5
36,228		1,867,806		1,867,806	6
222					7
131,985		6,534,160		6,534,160	8
40		2,800		2,800	9
136		4,427		4,427	10
25,400		1,347,464		1,347,464	11
32		1,692		1,692	12
4,515		212,550		212,550	13
					14
57,436	493,689	1,169,617	307,635	1,970,941	
2,686,211	0	143,885,041	9,092,175	152,977,216	
2,743,647	**493,689**	**145,054,658**	**9,399,810**	**154,948,157**	

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	04/11/2008	2007/Q4

FOOTNOTE DATA

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

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

Schedule Page: 310 Line No.: 3 Column: j
Prior Year Adjustment.

Schedule Page: 310 Line No.: 5 Column: i
Non-Firm Sales.

Schedule Page: 310 Line No.: 7 Column: i
Non-Firm Sales.

Schedule Page: 310 Line No.: 9 Column: j
Spinning or Operating Reserves.

Schedule Page: 310 Line No.: 10 Column: i
Unit Contingent.

Schedule Page: 310 Line No.: 11 Column: j
Financial Transmission Losses.

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

Schedule Page: 310.1 Line No.: 3 Column: i
Non-Firm Sales.

Schedule Page: 310.1 Line No.: 5 Column: i
Non-Firm Sales.

Schedule Page: 310.1 Line No.: 8 Column: i
Non-Firm Sales.

Schedule Page: 310.1 Line No.: 10 Column: j
Financial Transmission Losses.

Schedule Page: 310.1 Line No.: 11 Column: i
Non-Firm Sales.

Schedule Page: 310.2 Line No.: 2 Column: j
Financial Transmission Losses.

Schedule Page: 310.2 Line No.: 5 Column: i
Unit Contingent.

Schedule Page: 310.2 Line No.: 6 Column: j
Financial Transmission Losses.

Schedule Page: 310.2 Line No.: 7 Column: i
Non-Firm Sales.

Schedule Page: 310.3 Line No.: 3 Column: i
Non-Firm Sales.

Schedule Page: 310.3 Line No.: 8 Column: j
Financial Transmission Losses.

Schedule Page: 310.3 Line No.: 9 Column: i
Non-Firm Sales.

Schedule Page: 310.3 Line No.: 11 Column: i
Unit Contingent.

Schedule Page: 310.3 Line No.: 12 Column: i
Non-Firm Sales.

Schedule Page: 310.4 Line No.: 2 Column: j
Capacity and Penalty Charge.

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

Schedule Page: 310.4 Line No.: 6 Column: i
Non-Firm Sales.

Schedule Page: 310.4 Line No.: 9 Column: j
Spinning or Operating Reserves.

Name of Respondent Idaho Power Company	This Report is: (1) X An Original (2) __ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report 2007/Q4

FOOTNOTE DATA

Schedule Page: 310.4 Line No.: 10 Column: j
Financial Transmission Losses.

Schedule Page: 310.4 Line No.: 11 Column: i
Non-Firm Sales.

Schedule Page: 310.4 Line No.: 13 Column: j
Spinning or Operating Reserves.

Schedule Page: 310.4 Line No.: 14 Column: j
Financial Transmission Losses.

Schedule Page: 310.5 Line No.: 1 Column: i
Non-Firm Sales.

Schedule Page: 310.5 Line No.: 3 Column: j
Financial Transmission Losses.

Schedule Page: 310.5 Line No.: 5 Column: i
Unit Contingent.

Schedule Page: 310.5 Line No.: 6 Column: j
Financial Transmission Losses.

Schedule Page: 310.5 Line No.: 7 Column: i
Non-Firm Sales.

Schedule Page: 310.5 Line No.: 9 Column: j
Spinning or Operating Reserves.

Schedule Page: 310.5 Line No.: 10 Column: j
Financial Transmission Losses.

Schedule Page: 310.5 Line No.: 14 Column: i
Non-Firm Sales.

Schedule Page: 310.6 Line No.: 3 Column: j
Financial Transmission Losses.

Schedule Page: 310.6 Line No.: 4 Column: i
Non-Firm Sales.

Schedule Page: 310.6 Line No.: 6 Column: i
Non-Firm Sales.

Schedule Page: 310.6 Line No.: 9 Column: i
Unit Contingent.

Schedule Page: 310.6 Line No.: 10 Column: j
Financial Transmission Losses.

Schedule Page: 310.6 Line No.: 13 Column: j
Financial Transmission Losses.

Schedule Page: 310.6 Line No.: 14 Column: i
Non-Firm Sales.

Schedule Page: 310.7 Line No.: 3 Column: i
Non-Firm Sales.

Schedule Page: 310.7 Line No.: 9 Column: i
Non-Firm Sales.

Schedule Page: 310.7 Line No.: 12 Column: i
Non-Firm Sales.

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	04/11/2008	End of 2007/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	1,664,872	1,712,505
5	(501) Fuel	114,837,238	107,519,847
6	(502) Steam Expenses	6,840,109	7,107,143
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	2,109,888	1,444,277
10	(506) Miscellaneous Steam Power Expenses	8,068,234	8,142,999
11	(507) Rents	295,774	248,624
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	133,816,115	126,175,395
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	2,580,247	2,525,470
16	(511) Maintenance of Structures	649,264	408,848
17	(512) Maintenance of Boiler Plant	14,630,059	15,377,469
18	(513) Maintenance of Electric Plant	5,685,377	4,433,882
19	(514) Maintenance of Miscellaneous Steam Plant	5,934,851	4,575,617
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	29,479,798	27,321,286
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	163,295,913	153,496,681
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	5,235,531	4,522,312
45	(536) Water for Power	5,057,110	4,937,659
46	(537) Hydraulic Expenses	9,469,966	8,258,502
47	(538) Electric Expenses	1,391,453	1,387,391
48	(539) Miscellaneous Hydraulic Power Generation Expenses	2,825,559	2,407,071
49	(540) Rents	419,652	409,491
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	24,399,271	21,922,426
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	1,875,540	1,871,365
54	(542) Maintenance of Structures	1,281,835	1,193,327
55	(543) Maintenance of Reservoirs, Dams, and Waterways	541,034	946,682
56	(544) Maintenance of Electric Plant	2,090,274	2,138,733
57	(545) Maintenance of Miscellaneous Hydraulic Plant	2,763,207	3,213,655
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	8,551,890	9,363,762
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	32,951,161	31,286,188

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	341,622	322,341
63	(547) Fuel	19,484,750	7,498,309
64	(548) Generation Expenses	381,996	290,352
65	(549) Miscellaneous Other Power Generation Expenses	464,825	297,218
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	20,673,193	8,408,220
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		173
70	(552) Maintenance of Structures	220,422	176,972
71	(553) Maintenance of Generating and Electric Plant	42,703	124,319
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	645,761	392,516
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	908,886	693,980
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	21,582,079	9,102,200
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	289,484,214	283,439,877
77	(556) System Control and Load Dispatching	77,489	76,140
78	(557) Other Expenses	-118,678,522	-27,304,586
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	170,883,181	256,211,431
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	388,712,334	450,096,500
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	2,334,833	2,537,078
84	(561) Load Dispatching	51,610	1,166,233
85	(561.1) Load Dispatch-Reliability		565
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	2,042,253	1,525,337
87	(561.3) Load Dispatch-Transmission Service and Scheduling	1,098,119	765,078
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	66,918	29,062
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	1,748,409	1,866,905
94	(563) Overhead Lines Expenses	924,264	869,797
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	10,469,726	7,638,680
97	(566) Miscellaneous Transmission Expenses	622,227	270,768
98	(567) Rents	1,163,462	1,152,152
99	TOTAL Operation (Enter Total of lines 83 thru 98)	20,521,821	17,821,655
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	442,117	460,937
102	(569) Maintenance of Structures	111	
103	(569.1) Maintenance of Computer Hardware	123,219	98,980
104	(569.2) Maintenance of Computer Software	307,535	93,345
105	(569.3) Maintenance of Communication Equipment	21,369	5,757
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	2,899,130	2,900,424
108	(571) Maintenance of Overhead Lines	2,341,428	2,257,538
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	2,527	31,222
111	TOTAL Maintenance (Total of lines 101 thru 110)	6,137,436	5,848,203
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	26,659,257	23,669,858

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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	3,350,727	3,051,138
135	(581) Load Dispatching	3,049,911	3,020,110
136	(582) Station Expenses	1,120,906	1,159,883
137	(583) Overhead Line Expenses	3,432,084	3,856,696
138	(584) Underground Line Expenses	2,120,824	2,042,167
139	(585) Street Lighting and Signal System Expenses	148,817	154,596
140	(586) Meter Expenses	4,526,255	4,288,265
141	(587) Customer Installations Expenses	1,371,291	1,148,759
142	(588) Miscellaneous Expenses	5,533,555	5,589,808
143	(589) Rents	644,840	149,968
144	TOTAL Operation (Enter Total of lines 134 thru 143)	25,299,210	24,461,390
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	262,635	223,168
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	3,493,145	2,826,028
149	(593) Maintenance of Overhead Lines	12,504,013	11,020,129
150	(594) Maintenance of Underground Lines	1,351,054	1,114,786
151	(595) Maintenance of Line Transformers	169,689	583,246
152	(596) Maintenance of Street Lighting and Signal Systems	476,928	711,171
153	(597) Maintenance of Meters	927,906	895,593
154	(598) Maintenance of Miscellaneous Distribution Plant	127,981	148,970
155	TOTAL Maintenance (Total of lines 146 thru 154)	19,313,351	17,523,091
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	44,612,561	41,984,481
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	454,931	537,023
160	(902) Meter Reading Expenses	5,422,624	5,254,777
161	(903) Customer Records and Collection Expenses	8,177,910	10,146,625
162	(904) Uncollectible Accounts	2,009,863	2,848,490
163	(905) Miscellaneous Customer Accounts Expenses	336	373
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	16,065,664	18,787,288

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	301,871	288,822
168	(908) Customer Assistance Expenses	21,911,476	9,047,316
169	(909) Informational and Instructional Expenses		200
170	(910) Miscellaneous Customer Service and Informational Expenses	884,228	847,736
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	23,097,575	10,184,074
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	49,783,914	48,935,653
182	(921) Office Supplies and Expenses	17,790,599	14,665,999
183	(Less) (922) Administrative Expenses Transferred-Credit	27,708,517	29,324,259
184	(923) Outside Services Employed	11,232,903	8,149,646
185	(924) Property Insurance	3,159,426	2,945,897
186	(925) Injuries and Damages	5,448,358	5,152,000
187	(926) Employee Pensions and Benefits	27,872,099	29,241,894
188	(927) Franchise Requirements	1,200	2,000
189	(928) Regulatory Commission Expenses	6,030,254	976,225
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	519,844	107,310
192	(930.2) Miscellaneous General Expenses	3,497,158	1,901,158
193	(931) Rents	11,570	4,003
194	TOTAL Operation (Enter Total of lines 181 thru 193)	97,638,808	82,757,526
195	Maintenance		
196	(935) Maintenance of General Plant	3,771,715	3,969,367
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	101,410,523	86,726,893
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	600,557,914	631,449,094

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	04/11/2008	End of 2007/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Willis and Betty Deveny/Shinglecr	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	N/A	N/A
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	N/A	N/A
10	Snake River Pottery	LU	-	N/A	N/A	N/A
11	White Water Ranch	LU	-	N/A	N/A	N/A
12	John R LeMoyne	LU	-	N/A	N/A	N/A
13	David R Snedigar	LU	-	N/A	N/A	N/A
14	Mud Creek White Hydro, Inc	LU	-	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2008	End of 2007/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
622				40,247		40,247	1
3,446				218,146		218,146	2
34,334			1,576,498	1,068,516		2,645,014	3
							4
6,086				110,704		110,704	5
23,855				433,924		433,924	6
12,560				1,198,659		1,198,659	7
1,089				77,396		77,396	8
256			17,500	5,155		22,655	9
401				26,019		26,019	10
497				32,507		32,507	11
640				34,756		34,756	12
1,236				80,897		80,897	13
337				20,769		20,769	14
5,195,964	104,827	293,024	2,815,124	285,857,825	811,265	289,484,214	

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	04/11/2008	End of 2007/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Rim View Trout Company	OS	-	N/A	N/A	N/A
2	Curry Cattle Company	LU	-	.084Mw	N/A	N/A
3	Branchflower 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	N/A	N/A
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) 04/11/2008	Year/Period of Report End of 2007/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
1,360				58,227		58,227	1
637			26,796	12,814		39,610	2
846				57,129		57,129	3
							4
319				21,707		21,707	5
1,352				93,086		93,086	6
1,115				76,718		76,718	7
897				37,648		37,648	8
							9
1,732				122,988		122,988	10
2,071				137,267		137,267	11
7,308			552,508	147,042		699,550	12
							13
1,655				103,465		103,465	14
5,195,964	104,827	293,024	2,815,124	285,857,825	811,265	289,484,214	

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	04/11/2008	End of 2007/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	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	N/A	N/A
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	N/A	N/A
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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2008	End of 2007/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
3,590				231,615		231,615	1
673				28,223		28,223	2
1,172				75,317		75,317	3
1,732			155,672	34,846		190,518	4
3,305				240,153		240,153	5
3,488				265,510		265,510	6
2,445				179,438		179,438	7
3,751				257,366		257,366	8
5,430				329,588		329,588	9
6,402				412,324		412,324	10
7,312			486,150	127,891		614,041	11
							12
3,023				219,583		219,583	13
10,435				504,472		504,472	14
5,195,964	104,827	293,024	2,815,124	285,857,825	811,265	289,484,214	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	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	LU	-	N/A	N/A	N/A
6	Little Wood River Irrigation Dist	LU	-	N/A	N/A	N/A
7	Marco Rancher's Irrigation Inc.	LU	-	N/A	N/A	N/A
8	Faulkner Brothers Hydro Inc.	LU	-	N/A	N/A	N/A
9	Magic Reservoir Hydro	LU	-	N/A	N/A	N/A
10	Bypass Limited	LU	-	N/A	N/A	N/A
11	SE Hazelton A LP	LU	-	N/A	N/A	N/A
12	Claudia Burkhardt/Sunshine Power	OS	-	N/A	N/A	N/A
13	Lemhi Hydro Power Co./Schaffner	LU	-	N/A	N/A	N/A
14	J R Simplot Co.	LU	-	N/A	N/A	N/A
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
5,480				264,198		264,198	1
12,673				654,352		654,352	2
9,246				463,284		463,284	3
4,253				266,129		266,129	4
25,755				1,791,921		1,791,921	5
3,023				184,012		184,012	6
1,986				128,499		128,499	7
3,449				252,238		252,238	8
10,351				502,168		502,168	9
27,887				1,388,009		1,388,009	10
24,008				1,144,022		1,144,022	11
53				2,346		2,346	12
1,334				92,845		92,845	13
68,801				3,629,592		3,629,592	14
5,195,964	104,827	293,024	2,815,124	285,857,825	811,265	289,484,214	

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	04/11/2008	End of 2007/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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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.

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical 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	Blind Canyon Hydro	LU	-	N/A	N/A	N/A
2	City of Hailey	LU	-	N/A	N/A	N/A
3	City of Pocatello	LU	-	N/A	N/A	N/A
4	Marysville Hydro Partners/Falls R	LU	-	N/A	N/A	N/A
5	Wilson Power Company	LU	-	N/A	N/A	N/A
6	Hazelton B Power Company	LU	-	N/A	N/A	N/A
7	Pristine Springs Inc. #1	LU	-	N/A	N/A	N/A
8	Vaagen Brothers Lumber Inc.	LU	-	N/A	N/A	N/A
9	Horseshoe Bend Hydro	LU	-	N/A	N/A	N/A
10	Contractors Power Group Inc./Mile	LU	-	N/A	N/A	N/A
11	Rupert Cogeneration Partners	LU	-	N/A	N/A	N/A
12	Glenns Ferry Cogeneration Partner	LU	-	N/A	N/A	N/A
13	Lewandowski Farms	OS	-	N/A	N/A	N/A
14	Tasco - Nampa	OS	-	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)	
4,458				343,080		343,080	1
182				12,210		12,210	2
1,482				103,668		103,668	3
42,358				2,468,166		2,468,166	4
26,812				1,753,579		1,753,579	5
23,673				1,545,300		1,545,300	6
925				48,754		48,754	7
20,369				1,423,138		1,423,138	8
46,122				2,957,457		2,957,457	9
3,694				244,816		244,816	10
50,740				3,090,613		3,090,613	11
54,101				3,176,012		3,176,012	12
60				2,676		2,676	13
344				14,450		14,450	14
5,195,964	104,827	293,024	2,815,124	285,857,825	811,265	289,484,214	

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	04/11/2008	End of 2007/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Pristine Springs Inc # 3	LU	-	N/A	N/A	N/A
2	Ted S. Sorenson/Tiber Dam	LU		N/A	N/A	N/A
3	Fossil Gulch Wind	LU	-	N/A	N/A	N/A
4	G2 Energy Hidden Hollow	LU		N/A	N/A	N/A
5	Horseshoe Bend Wind/United Materi	LU		N/A	N/A	N/A
6	Horseshoe Bend Wind/United Materi	LU		N/A	N/A	N/A
7	Horseshoe Bend Wind/United Materi	LU		N/A	N/A	N/A
8	Riverside Hydro Mora Drop	LU		N/A	N/A	N/A
9	J.M. Miller/Sahko Hydro	LU		N/A	N/A	N/A
10	D.R. Johnson Lumber/Co Gen Co	SF		N/A	N/A	N/A
11	Twin Falls Energy / Lowline Midwa	LU				
12	US Geothermal / Raft River Geothe	LU				
13	Other Purchased Power					
14	Arizona Public Service Co.	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) 04/11/2008	Year/Period of Report End of 2007/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
1,405				72,966		72,966	1
29,910				1,386,319		1,386,319	2
23,332				1,120,523		1,120,523	3
18,327				914,885		914,885	4
21,773				1,038,353		1,038,353	5
5							6
4							7
4,622				196,200		196,200	8
922				39,362		39,362	9
35,411				2,290,170		2,290,170	10
3,196				203,886		203,886	11
7,221				346,623		346,623	12
							13
140,817				8,718,102		8,718,102	14
5,195,964	104,827	293,024	2,815,124	285,857,825	811,265	289,484,214	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Avista Corp. - WWP Div.	SF	T-12	N/A	N/A	N/A
2	Avista Corp. - WWP Div.	OS	WSPP	N/A	N/A	N/A
3	Avista Corp. - WWP Div.	SF	WSPP	N/A	N/A	N/A
4	Avista Corp. - WWP Div.	OS	WSPP	N/A	N/A	N/A
5	Avista Energy, Inc.	OS	WSPP	N/A	N/A	N/A
6	Avista Energy, Inc.	SF	WSPP	N/A	N/A	N/A
7	Barclays Bank PLC	SF	WSPP	N/A	N/A	N/A
8	Bear Energy LP	SF	WSPP	N/A	N/A	N/A
9	Benton County PUD	OS	WSPP	N/A	N/A	N/A
10	Benton County PUD	SF	WSPP	N/A	N/A	N/A
11	Black Hills Power Inc.	OS	WSPP	N/A	N/A	N/A
12	Black Hills Power Inc.	SF	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
	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)	
106				5,364		5,364	1
770				37,065		37,065	2
20,361				686,922		686,922	3
					852,647	852,647	4
2,827				149,783		149,783	5
35,095				1,684,871		1,684,871	6
233,325				13,282,575		13,282,575	7
1,200				68,200		68,200	8
255				11,580		11,580	9
5,378				239,890		239,890	10
26,137				1,489,381		1,489,381	11
8,852				505,844		505,844	12
11,084				697,572		697,572	13
113,654				4,736,870		4,736,870	14
5,195,964	104,827	293,024	2,815,124	285,857,825	811,265	289,484,214	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	BP Energy Company	OS	WSPP	N/A	N/A	N/A
2	BP Energy Company	SF	WSPP	N/A	N/A	N/A
3	BP Energy Company	SF	WSPP	N/A	N/A	N/A
4	Calpine Energy Services, L.P.	SF	WSPP	N/A	N/A	N/A
5	Cargill Power Markets LLC	OS	WSPP	N/A	N/A	N/A
6	Cargill Power Markets LLC	SF	WSPP	N/A	N/A	N/A
7	Chelan Co PUD	SF	WSPP	N/A	N/A	N/A
8	Citigroup Energy Inc.	OS	WSPP	N/A	N/A	N/A
9	Citigroup Energy Inc.	SF	WSPP	N/A	N/A	N/A
10	Clatskanie PUD	OS	WSPP	N/A	N/A	N/A
11	Clatskanie PUD	SF	WSPP	N/A	N/A	N/A
12	Conoco Phillips Company	SF	WSPP	N/A	N/A	N/A
13	Constellation Energy Commodities	SF	WSPP	N/A	N/A	N/A
14	Coral Power, LLC	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 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.
41				2,798		2,798	1
430,080				26,441,133		26,441,133	2
					378	378	3
7,313				373,060		373,060	4
85				3,885		3,885	5
23,988				1,267,530		1,267,530	6
8,235				341,675		341,675	7
100				9,500		9,500	8
98,747				4,917,363		4,917,363	9
10				930		930	10
1,606				76,611		76,611	11
2,525				282,275		282,275	12
167,800				8,530,981		8,530,981	13
219,760				10,402,311		10,402,311	14
5,195,964	104,827	293,024	2,815,124	285,857,825	811,265	289,484,214	

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	04/11/2008	End of 2007/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Credit Suisse Energy LLC	SF	WSPP	N/A	N/A	N/A
2	DB Energy Trading, LLC	SF	WSPP	N/A	N/A	N/A
3	Douglas County PUD	SF	WSPP	N/A	N/A	N/A
4	El Paso Electric Company	SF	WSPP	N/A	N/A	N/A
5	Energy Authority, The	SF	WSPP	N/A	N/A	N/A
6	Eugene Water & Electric Board	OS	WSPP	N/A	N/A	N/A
7	Eugene Water & Electric Board	SF	WSPP	N/A	N/A	N/A
8	Fortis Energy Marketing & Trading	SF	WSPP	N/A	N/A	N/A
9	Franklin County P.U.D.	OS	WSPP	N/A	N/A	N/A
10	Franklin County P.U.D.	SF	WSPP	N/A	N/A	N/A
11	Grant County P.U.D.	OS	WSPP	N/A	N/A	N/A
12	Grant County P.U.D.	SF	WSPP	N/A	N/A	N/A
13	Grays Harbor PUD	OS	WSPP	N/A	N/A	N/A
14	Grays Harbor PUD	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: 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 ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
37,231				2,559,050		2,559,050	1
400				22,900		22,900	2
2,405				99,515		99,515	3
685				47,165		47,165	4
2,955				116,320		116,320	5
50				3,400		3,400	6
12,420				697,847		697,847	7
19,600				1,068,800		1,068,800	8
200				8,755		8,755	9
1,523				76,121		76,121	10
14,880				393,080		393,080	11
21,510				1,085,665		1,085,665	12
195				8,845		8,845	13
4,772				237,370		237,370	14
5,195,964	104,827	293,024	2,815,124	285,857,825	811,265	289,484,214	

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	04/11/2008	End of 2007/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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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.

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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	Highland Energy LLC	SF	WSPP	N/A	N/A	N/A
2	J. Aron & Company	SF	WSPP	N/A	N/A	N/A
3	Lehman Brothers Commodity Service	SF	WSPP	N/A	N/A	N/A
4	Los Angeles Department of Water a	SF	WSPP	N/A	N/A	N/A
5	Morgan Stanley Capital Group Inc.	OS	WSPP	N/A	N/A	N/A
6	Morgan Stanley Capital Group Inc.	SF	WSPP	N/A	N/A	N/A
7	Nevada Power Company	SF	WSPP	N/A	N/A	N/A
8	NorthWestern Energy	SF	T-7	N/A	N/A	N/A
9	NorthWestern Energy	OS	WSPP	N/A	N/A	N/A
10	NorthWestern Energy	SF	WSPP	N/A	N/A	N/A
11	NorthWestern Energy	IF	242	N/A	N/A	N/A
12	Okanogan County P.U.D.	SF	WSPP	N/A	N/A	N/A
13	Pacific Northwest Generating Coop	SF	WSPP	N/A	N/A	N/A
14	PacifiCorp Inc.	SF	T-13	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) 04/11/2008	Year/Period of Report End of 2007/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
325				18,825		18,825	1
36,400				1,552,700		1,552,700	2
65,800				2,815,552		2,815,552	3
397				48,665		48,665	4
225				10,770		10,770	5
93,969				5,604,153		5,604,153	6
1,065				58,120		58,120	7
144				7,004		7,004	8
302				14,849		14,849	9
2,377				109,408		109,408	10
65,820				3,257,201		3,257,201	11
240				5,520		5,520	12
9,000				364,150		364,150	13
820				40,862		40,862	14
5,195,964	104,827	293,024	2,815,124	285,857,825	811,265	289,484,214	

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	04/11/2008	End of 2007/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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1	PacifiCorp Inc.	OS	WSPP	N/A	N/A	N/A
2	PacifiCorp Inc.	SF	WSPP	N/A	N/A	N/A
3	PacifiCorp Inc.	OS	WSPP	N/A	N/A	N/A
4	Portland General Electric Company	SF	T-14	N/A	N/A	N/A
5	Portland General Electric Company	SF	-	N/A	N/A	N/A
6	Portland General Electric Company	OS	WSPP	N/A	N/A	N/A
7	Portland General Electric Company	SF	WSPP	N/A	N/A	N/A
8	Powerex Corp.	OS	WSPP	N/A	N/A	N/A
9	Powerex Corp.	SF	WSPP	N/A	N/A	N/A
10	PPL EnergyPlus, LLC	SF	WSPP	N/A	N/A	N/A
11	PPL Montana, LLC	LF	WSPP	N/A	N/A	N/A
12	PPL Montana, LLC	OS	WSPP	N/A	N/A	N/A
13	PPL Montana, LLC	SF	WSPP	N/A	N/A	N/A
14	PPM Energy, Inc.	OS	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) 04/11/2008	Year/Period of Report End of 2007/Q4

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

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4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
18,207				965,343		965,343	1
476,556				26,743,882		26,743,882	2
					1,618,117	1,618,117	3
214				10,818		10,818	4
2,112				31,178		31,178	5
5,320				295,340		295,340	6
121,122				6,787,873		6,787,873	7
1,048				91,963		91,963	8
176,828				10,654,308		10,654,308	9
36,684				2,236,138		2,236,138	10
103,584				4,609,488		4,609,488	11
14,368				706,349		706,349	12
122,917				5,753,694		5,753,694	13
1,057				59,725		59,725	14
5,195,964	104,827	293,024	2,815,124	285,857,825	811,265	289,484,214	

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(Including power exchanges)

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1	PPM Energy, Inc.	SF	WSPP	N/A	N/A	N/A
2	Public Service Co. of Colorado	SF	WSPP	N/A	N/A	N/A
3	Public Service Company of New Mex	SF	WSPP	N/A	N/A	N/A
4	Puget Sound Energy, Inc.	SF	T-9	N/A	N/A	N/A
5	Puget Sound Energy, Inc.	OS	WSPP	N/A	N/A	N/A
6	Puget Sound Energy, Inc.	SF	WSPP	N/A	N/A	N/A
7	Rainbow Energy Marketing Corporat	OS	WSPP	N/A	N/A	N/A
8	Rainbow Energy Marketing Corporat	SF	WSPP	N/A	N/A	N/A
9	Salt River Project	SF	WSPP	N/A	N/A	N/A
10	San Diego Gas and Electric	SF	WSPP	N/A	N/A	N/A
11	Seattle City Light	OS	WSPP	N/A	N/A	N/A
12	Seattle City Light	SF	WSPP	N/A	N/A	N/A
13	Sempra Energy Solutions	SF	WSPP	N/A	N/A	N/A
14	Sempra Energy Trading 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	04/11/2008	End of 2007/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
150,549				9,301,790		9,301,790	1
46,045				2,408,599		2,408,599	2
6,675				443,997		443,997	3
196				9,590		9,590	4
1,127				53,646		53,646	5
46,352				2,315,564		2,315,564	6
4,692				241,393		241,393	7
6,180				261,675		261,675	8
3,055				240,110		240,110	9
800				47,100		47,100	10
1,300				74,090		74,090	11
39,965				1,851,960		1,851,960	12
400				15,900		15,900	13
374,322				23,844,426		23,844,426	14
5,195,964	104,827	293,024	2,815,124	285,857,825	811,265	289,484,214	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Sempra Energy Trading LLC	SF	WSPP	N/A	N/A	N/A
2	Sierra Pacific Power Company	SF	55	N/A	N/A	N/A
3	Sierra Pacific Power Company	SF	WSPP	N/A	N/A	N/A
4	Sierra Pacific Power Company	SF	WSPP	N/A	N/A	N/A
5	Sierra Pacific Power Company	OS	WSPP	N/A	N/A	N/A
6	Silicon Valley Power	SF	WSPP	N/A	N/A	N/A
7	Snohomish County PUD	OS	WSPP	N/A	N/A	N/A
8	Snohomish County PUD	SF	WSPP	N/A	N/A	N/A
9	Southern California Edison	SF	WSPP	N/A	N/A	N/A
10	SUEZ Energy Marketing NA, Inc.	OS	WSPP	N/A	N/A	N/A
11	SUEZ Energy Marketing NA, Inc.	SF	WSPP	N/A	N/A	N/A
12	Tacoma Power	OS	WSPP	N/A	N/A	N/A
13	Tacoma Power	SF	WSPP	N/A	N/A	N/A
14	Telocaset Wind Power Partners LLC	LU	APP-A	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	04/11/2008	End of 2007/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
207,404				14,302,530		14,302,530	1
97				4,679		4,679	2
5,031				211,980		211,980	3
					360	360	4
					6,635	6,635	5
600				24,550		24,550	6
710				42,550		42,550	7
16,981				580,605		580,605	8
800				46,000		46,000	9
250				14,050		14,050	10
17,410				1,055,710		1,055,710	11
2,045				93,780		93,780	12
5,693				314,494		314,494	13
16,934				741,432		741,432	14
5,195,964	104,827	293,024	2,815,124	285,857,825	811,265	289,484,214	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	TransAlta Energy Marketing (U.S.)	OS	WSPP	N/A	N/A	N/A
2	TransAlta Energy Marketing (U.S.)	SF	WSPP	N/A	N/A	N/A
3	Tucson Electric Power Company	SF	WSPP	N/A	N/A	N/A
4	UBS AG, London Branch	SF	WSPP	N/A	N/A	N/A
5	UBS Securities LLC	OS	-			
6	Utah Associated Municipal Power S	SF	WSPP	N/A	N/A	N/A
7	Western Area Power Administration	SF	WSPP	N/A	N/A	N/A
8	Western Area Power Administration	SF	WSPP	N/A	N/A	N/A
9	Net Metering Customers	OS	-	N/A	N/A	N/A
10	BAD DEBT WRITE-OFF	-	-			
11	Power Exchanges					
12	Bonneville Power Administration	EX	-			
13	Citigroup Energy Inc.	EX	-			
14	Coral Power, LLC	EX	-			
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
1,391				64,840		64,840	1
145,346				6,951,901		6,951,901	2
2,400				166,700		166,700	3
277,600				13,176,700		13,176,700	4
							5
129				4,515		4,515	6
25				1,325		1,325	7
61				3,325		3,325	8
365				24,604		24,604	9
					-1,666,872	-1,666,872	10
							11
	57,713	20,936					12
	17						13
	78						14
5,195,964	104,827	293,024	2,815,124	285,857,825	811,265	289,484,214	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	NorthWestern Energy	EX	-			
2	PacifiCorp Inc.	EX	-			
3	Puget Sound Energy, Inc.	EX	-			
4	Sierra Pacific Power Company	EX	-			
5	Utah Associated Municipal Power S	EX	-			
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
		5,529					1
	46,219	250,742					2
	795						3
		15,817					4
	5						5
							6
							7
							8
							9
							10
							11
							12
							13
							14
5,195,964	104,827	293,024	2,815,124	285,857,825	811,265	289,484,214	

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 Company. The actual demand is not used in determining the cost of energy.

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

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

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

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

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

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

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

Schedule Page: 326.4 Line No.: 13 Column: b
Non-Firm Purchases.

Schedule Page: 326.4 Line No.: 14 Column: b
Non-Firm Purchases.

Schedule Page: 326.5 Line No.: 6 Column: b
Energy difference between mountain and pacific time schedules.

Schedule Page: 326.5 Line No.: 7 Column: b
Energy Difference between scheduled and actual receipts from small power producers.

Schedule Page: 326.6 Line No.: 2 Column: b
Non-Firm Purchases.

Schedule Page: 326.6 Line No.: 4 Column: b
Financial Transmission Losses.

Schedule Page: 326.6 Line No.: 5 Column: b
Non-Firm Purchases.

Schedule Page: 326.6 Line No.: 9 Column: b
Non-Firm Purchases.

Schedule Page: 326.6 Line No.: 11 Column: b
Non-Firm Purchases.

Schedule Page: 326.6 Line No.: 13 Column: b
Non-Firm Purchases.

Schedule Page: 326.7 Line No.: 1 Column: b
Non-Firm Purchases.

Schedule Page: 326.7 Line No.: 3 Column: b
Liquidated Damages.

Schedule Page: 326.7 Line No.: 5 Column: b
Non-Firm Purchases.

Schedule Page: 326.7 Line No.: 8 Column: b
Non-Firm Purchases.

Schedule Page: 326.7 Line No.: 10 Column: b
Non-Firm Purchases.

Schedule Page: 326.8 Line No.: 6 Column: b
Non-Firm Purchases.

Schedule Page: 326.8 Line No.: 9 Column: b
Non-Firm Purchases.

Schedule Page: 326.8 Line No.: 11 Column: b
Non-Firm Purchases.

Schedule Page: 326.8 Line No.: 13 Column: b
Non-Firm Purchases.

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

Schedule Page: 326.9 Line No.: 9 Column: b
Non-Firm Purchases.

Schedule Page: 326.10 Line No.: 1 Column: b
Non-Firm Purchases.

Schedule Page: 326.10 Line No.: 3 Column: b
Financial Transmission Losses.

Schedule Page: 326.10 Line No.: 5 Column: b
Energy received from PGE in lieu of Boardman generation in accordance with the "Assured" energy agreement between PGE and Idaho Power, Dated 11/17/1989.

Schedule Page: 326.10 Line No.: 6 Column: b
Non-Firm Purchases.

Schedule Page: 326.10 Line No.: 8 Column: b
Non-Firm Purchases.

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

Schedule Page: 326.10 Line No.: 14 Column: b
Non-Firm Purchases.

Schedule Page: 326.11 Line No.: 5 Column: b
Non-Firm Purchases.

Schedule Page: 326.11 Line No.: 7 Column: b
Non-Firm Purchases.

Schedule Page: 326.11 Line No.: 11 Column: b
Non-Firm Purchases.

Schedule Page: 326.12 Line No.: 4 Column: b
Spinning or Operating Reserves.

Schedule Page: 326.12 Line No.: 5 Column: b
Financial Transmission Losses.

Schedule Page: 326.12 Line No.: 7 Column: b
Non-Firm Purchases.

Schedule Page: 326.12 Line No.: 10 Column: b
Non-Firm Purchases.

Schedule Page: 326.12 Line No.: 12 Column: b
Non-Firm Purchases.

Schedule Page: 326.13 Line No.: 1 Column: b
Non-Firm Purchases.

Schedule Page: 326.13 Line No.: 5 Column: b
Institutional Futures Client Account Agreement with UBS, dated March 8, 2006.

Schedule Page: 326.13 Line No.: 9 Column: b
Schedule 84 Net Metering.

Schedule Page: 326.13 Line No.: 12 Column: b
Scheduled losses not removed with loss transactions.

Schedule Page: 326.13 Line No.: 13 Column: b
Scheduled losses not removed with loss transactions.

Schedule Page: 326.13 Line No.: 14 Column: b
Scheduled losses not removed with loss transactions.

Schedule Page: 326.14 Line No.: 1 Column: b
Scheduled losses not removed with loss transactions.

Schedule Page: 326.14 Line No.: 2 Column: b
Scheduled losses not removed with loss transactions.

Schedule Page: 326.14 Line No.: 3 Column: b
Scheduled losses not removed with loss transactions.

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Schedule Page: 326.14 Line No.: 4 Column: b

Scheduled losses not removed with loss transactions.

Schedule Page: 326.14 Line No.: 5 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) 04/11/2008	Year/Period of Report End of 2007/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Bonneville Power Administration - OT	Bonneville Power Administratio	Oregon Trails Electric Co-op	FNO
2	Bonneville Power Administration - OT			AD
3	Bonneville Power Administration - US	Bonneville Power Administratio	United States Bureau of Reclama	FNO
4	Bonneville Power Administration - US			AD
5	Bonneville Power Administration - Ra	Bonneville Power Administratio	Raft River Electric Co-op	FNO
6	Bonneville Power Administration - Ra			AD
7	Bonneville Power Administration - PF	Bonneville Power Administratio	Priority Firm Customers	FNO
8	Bonneville Power Administration - PF			AD
9	Milner Irrigation District	United States Bureau of Reclam	Milner Irrigation District	OLF
10	City of Seattle	Seattle City Light	Bonneville Power Administration	OLF
11	PacifiCorp	PacifiCorp West	PacifiCorp West	FNO
12	PacifiCorp	PacifiCorp West	PacifiCorp West	AD
13	United States Bureau of Indian Affai	Bonneville Power Administratio	United States Bureau of Indian	OS
14	Pacificorp Power Marketing			AD
15	Pacificorp Power Marketing	PacifiCorp West	PacifiCorp West	OS
16	Pacificorp Power Marketing	PacifiCorp East	PacifiCorp West	OS
17	Avista Energy, Inc.	Sierra Pacific Power	PacifiCorp East	NF
18	Avista Energy, Inc.	PacifiCorp East	Sierra Pacific Power	NF
19	Avista Energy, Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
20	Avista Energy, Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
21	Avista Energy, Inc.	Avista	Sierra Pacific Power	NF
22	Avista Energy, Inc.	Bonneville Power Administratio	Sierra Pacific Power	NF
23	Avista Energy, Inc.			AD
24	Black Hills Power	Bonneville Power Administratio	PacifiCorp West	NF
25	Black Hills Power	PacifiCorp West	Bonneville Power Administration	NF
26	Black Hills Power			AD
27	Boneville Power Admin.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
28	Boneville Power Admin.	PacifiCorp West	Bonneville Power Administration	NF
29	Boneville Power Admin.	Avista	Sierra Pacific Power	NF
30	Boneville Power Admin.	PacifiCorp East	Bonneville Power Administration	NF
31	Boneville Power Admin.	PacifiCorp West	Sierra Pacific Power	NF
32	Boneville Power Admin.	PacifiCorp West	Bonneville Power Administration	NF
33	Boneville Power Admin.	Avista	Bonneville Power Administration	NF
34	Boneville Power Admin.	Bonneville Power Administratio	Sierra Pacific Power	NF
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2008	End of 2007/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
5				389,447	389,447	1
5						2
5				-88,744	-88,744	3
5						4
5				226,163	226,163	5
5						6
5				756,307	756,307	7
5						8
Legacy	Minidoka, Idaho	Various in Idaho		8,687	8,687	9
Legacy	LYPK	LGBP				10
5				2,085	2,085	11
5						12
legacy	LaGrande, Oregon	Various in Idaho		15,975	15,975	13
Legacy (414)						14
Legacy (440)	JBSN	ENPR		6,031	6,031	15
Legacy (433)	BOBR	JBSN		91,797	91,797	16
5	M345	BOBR		10	10	17
5	BOBR	M345		30	30	18
5	HTSP	M345		32	32	19
5	HTSP	BOBR		972	972	20
5	LOLO	M345		1,847	1,847	21
5	LGBP	M345		3,501	3,501	22
5						23
5	LGBP	JBSN		5	5	24
5	JBSN	LGBP		475	475	25
5						26
5	HTSP	BOBR		18	18	27
5	ENPR	LGBP		150	150	28
5	LOLO	M345		476	476	29
5	BOBR	LGBP		927	927	30
5	ENPR	M345		1,510	1,510	31
5	JBSN	LGBP		2,352	2,352	32
5	LOLO	LGBP		2,360	2,360	33
5	LGBP	M345		23,196	23,196	34
			0	4,052,567	4,052,567	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

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

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

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

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
5						1
5	M345	LGBP		25	25	2
5	M345	ENPR		35	35	3
5	LGBP	IPCO		50	50	4
5	JEFF	M345		57	57	5
5	LGBP	JBSN		59	59	6
5	LOLO	IPCO		68	68	7
5	BOBR	IPCO		125	125	8
5	BOBR	HTSP		336	336	9
5	BOBR	JBSN		444	444	10
5	JBSN	LOLO		678	678	11
5	LGBP	BOBR		826	826	12
5	MLCK	BOBR		845	845	13
5	LOLO	BOBR		1,646	1,646	14
5	HTSP	M345		2,347	2,347	15
5	JBSN	BOBR		6,101	6,101	16
5	LOLO	M345		12,426	12,426	17
5	LGBP	M345		17,666	17,666	18
5	HTSP	BOBR		22,983	22,983	19
5	JBSN	LGBP		28,892	28,892	20
5	BOBR	LGBP		31,495	31,495	21
5	JBSN	M345		59,375	59,375	22
5	ENPR	M345		115,512	115,512	23
5	ENPR	BOBR		131,737	131,737	24
5	BOBR	M345		195,737	195,737	25
5	BOBR	M345		27,705	27,705	26
5						27
5	HTSP	BOBR		294	294	28
5	LGBP	BOBR		588	588	29
5	HTSP	M345		51	51	30
5	LGBP	M345		120	120	31
5	MLCK	BOBR		105	105	32
5	HTSP	BOBR		170	170	33
5	BOBR	LOLO		173	173	34
			0	**4,052,567**	**4,052,567**	

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	04/11/2008	End of 2007/Q4

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
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Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Coral Power	Bonneville Power Administratio	Sierra Pacific Power	NF
2	Coral Power	PacifiCorp East	Bonneville Power Administration	NF
3	Coral Power	PacifiCorp East	Sierra Pacific Power	NF
4	Energy Authority, The			NF
5	Integrys Energy			NF
6	Morgan Stanley Capital Group (INCLUD	PacifiCorp West	PacifiCorp West	NF
7	Morgan Stanley Capital Group (INCLUD	PacifiCorp West	PacifiCorp West	NF
8	Morgan Stanley Capital Group (INCLUD	PacifiCorp West	Sierra Pacific Power	NF
9	Morgan Stanley Capital Group (INCLUD	PacifiCorp East	Avista	NF
10	Morgan Stanley Capital Group (INCLUD	Sierra Pacific Power	Bonneville Power Administration	NF
11	Morgan Stanley Capital Group (INCLUD	Avista	PacifiCorp East	NF
12	Morgan Stanley Capital Group (INCLUD	PacifiCorp West	PacifiCorp East	NF
13	Morgan Stanley Capital Group (INCLUD	Bonneville Power Administratio	Sierra Pacific Power	NF
14	Morgan Stanley Capital Group (INCLUD	PacifiCorp West	Bonneville Power Administration	NF
15	Morgan Stanley Capital Group (INCLUD	Bonneville Power Administratio	PacifiCorp East	NF
16	Morgan Stanley Capital Group (INCLUD	PacifiCorp East	Bonneville Power Administration	NF
17	Morgan Stanley Capital Group (INCLUD	PacifiCorp East	Sierra Pacific Power	NF
18	Morgan Stanley Capital Group (INCLUD	PacifiCorp East	PacifiCorp West	NF
19	Morgan Stanley Capital Group (INCLUD	Avista	Sierra Pacific Power	NF
20	Morgan Stanley Capital Group (INCLUD	PacifiCorp West	PacifiCorp East	NF
21	Morgan Stanley Capital Group (INCLUD			AD
22	Pacificorp Power Marketing	Avista	Sierra Pacific Power	NF
23	Pacificorp Power Marketing	PacifiCorp West	Sierra Pacific Power	NF
24	Pacificorp Power Marketing	PacifiCorp East	PacifiCorp West	NF
25	Pacificorp Power Marketing	PacifiCorp West	PacifiCorp East	NF
26	Pacificorp Power Marketing	PacifiCorp West	PacifiCorp East	NF
27	Pacificorp Power Marketing	PacifiCorp East	Sierra Pacific Power	NF
28	Pacificorp Power Marketing	PacifiCorp East	Sierra Pacific Power	SFP
29	Pacificorp Power Marketing			AD
30	Portland General Electric	NorthWestern/PacifiCorp East	PacifiCorp East	NF
31	Portland General Electric	Sierra Pacific Power	Bonneville Power Administration	NF
32	Portland General Electric	Bonneville Power Administratio	Sierra Pacific Power	NF
33	Portland General Electric	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
34	Portland General Electric	PacifiCorp East	Bonneville Power Administration	NF
	TOTAL			

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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
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FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
5	LGBP	M345		216	216	1
5	BOBR	LGBP		890	890	2
5	BOBR	M345		3,237	3,237	3
5						4
5						5
5	ENPR	JBSN		25	25	6
5	JBSN	ENPR		45	45	7
5	JBSN	M345		268	268	8
5	BOBR	LOLO		336	336	9
5	M345	LGBP		355	355	10
5	LOLO	BOBR		421	421	11
5	JBSN	BOBR		592	592	12
5	LGBP	M345		663	663	13
5	JBSN	LGBP		1,272	1,272	14
5	LGBP	BOBR		2,675	2,675	15
5	BOBR	LGBP		2,758	2,758	16
5	BOBR	M345		3,176	3,176	17
5	BOBR	ENPR		3,975	3,975	18
5	LOLO	M345		5,583	5,583	19
5	ENPR	BOBR		7,248	7,248	20
5						21
5	LOLO	M345		57	57	22
5	JBSN	M345		5,875	5,875	23
5	BOBR	ENPR		22,901	22,901	24
5	ENPR	BOBR		36,325	36,325	25
5	JBSN	BOBR		53,919	53,919	26
5	BOBR	M345		25,221	25,221	27
5	BOBR	M345		85,604	85,604	28
5						29
5	JEFF	BOBR		65	65	30
5	M345	LGBP		313	313	31
5	LGBP	M345		318	318	32
5	JEFF	M345		356	356	33
5	BOBR	LGBP		1,002	1,002	34
			0	4,052,567	4,052,567	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

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1	Portland General Electric	Bonneville Power Administratio	PacifiCorp East	NF
2	Portland General Electric	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
3	Portland General Electric			AD
4	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp East	NorthWestern/PacifiCorp East	NF
5	Powerex Corp. (INCLUDES REDIRECTS)	Sierra Pacific Power	PacifiCorp East	NF
6	Powerex Corp. (INCLUDES REDIRECTS)	Avista	PacifiCorp West	NF
7	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp East	NorthWestern/PacifiCorp East	NF
8	Powerex Corp. (INCLUDES REDIRECTS)	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
9	Powerex Corp. (INCLUDES REDIRECTS)	Sierra Pacific Power	PacifiCorp West	NF
10	Powerex Corp. (INCLUDES REDIRECTS)	NorthWestern/PacifiCorp East	PacifiCorp West	NF
11	Powerex Corp. (INCLUDES REDIRECTS)	Seattle City Light	NorthWestern/PacifiCorp East	NF
12	Powerex Corp. (INCLUDES REDIRECTS)	Seattle City Light	Avista	NF
13	Powerex Corp. (INCLUDES REDIRECTS)	Seattle City Light	PacifiCorp West	NF
14	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp West	PacifiCorp West	NF
15	Powerex Corp. (INCLUDES REDIRECTS)	Idaho Power Company	Bonneville Power Administration	NF
16	Powerex Corp. (INCLUDES REDIRECTS)	Sierra Pacific Power	PacifiCorp West	NF
17	Powerex Corp. (INCLUDES REDIRECTS)	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
18	Powerex Corp. (INCLUDES REDIRECTS)	NorthWestern/PacifiCorp East	PacifiCorp East	NF
19	Powerex Corp. (INCLUDES REDIRECTS)	Bonneville Power Administratio	Idaho Power Company	NF
20	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp West	NorthWestern/PacifiCorp East	NF
21	Powerex Corp. (INCLUDES REDIRECTS)	Bonneville Power Administratio	PacifiCorp West	NF
22	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp East	PacifiCorp West	NF
23	Powerex Corp. (INCLUDES REDIRECTS)	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
24	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp East	PacifiCorp West	NF
25	Powerex Corp. (INCLUDES REDIRECTS)	NorthWestern/PacifiCorp East	PacifiCorp West	NF
26	Powerex Corp. (INCLUDES REDIRECTS)	Seattle City Light	PacifiCorp East	NF
27	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp East	Avista	NF
28	Powerex Corp. (INCLUDES REDIRECTS)	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
29	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp West	PacifiCorp East	NF
30	Powerex Corp. (INCLUDES REDIRECTS)	Sierra Pacific Power	Bonneville Power Administration	NF
31	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp East	PacifiCorp West	NF
32	Powerex Corp. (INCLUDES REDIRECTS)	Seattle City Light	Bonneville Power Administration	NF
33	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp West	Sierra Pacific Power	NF
34	Powerex Corp. (INCLUDES REDIRECTS)	Bonneville Power Administratio	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) 04/11/2008	Year/Period of Report End of 2007/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
5	LGBP	BOBR		1,846	1,846	1
5	JEFF	LGBP		4,004	4,004	2
5						3
5	BOBR	JEFF		22	22	4
5	M345	BOBR		24	24	5
5	LOLO	JBSN		25	25	6
5	BOBR	HTSP		120	120	7
5	HTSP	LGBP		135	135	8
5	M345	ENPR		175	175	9
5	JEFF	JBSN		196	196	10
5	LYPK	JEFF		216	216	11
5	LYPK	LOLO		216	216	12
5	LYPK	M500		265	265	13
5	JBSN	ENPR		293	293	14
5	IPCO	LGBP		460	460	15
5	M345	M500		497	497	16
5	HTSP	M345		661	661	17
5	JEFF	BOBR		869	869	18
5	LGBP	IPCO		928	928	19
5	JBSN	JEFF		943	943	20
5	LGBP	JBSN		1,159	1,159	21
5	BOBR	JBSN		1,275	1,275	22
5	JEFF	M345		1,321	1,321	23
5	BOBR	ENPR		1,363	1,363	24
5	JEFF	M500		1,410	1,410	25
5	LYPK	BOBR		2,072	2,072	26
5	BOBR	LOLO		3,121	3,121	27
5	JEFF	LGBP		4,212	4,212	28
5	JBSN	BOBR		4,436	4,436	29
5	M345	LGBP		4,863	4,863	30
5	BOBR	M500		5,464	5,464	31
5	LYPK	LGBP		6,309	6,309	32
5	JBSN	M345		7,713	7,713	33
5	LGBP	BOBR		12,798	12,798	34
			0	4,052,567	4,052,567	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Powerex Corp. (INCLUDES REDIRECTS)	Avista	PacifiCorp East	NF
2	Powerex Corp. (INCLUDES REDIRECTS)	Avista	Sierra Pacific Power	NF
3	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp East	PacifiCorp East	NF
4	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp West	PacifiCorp West	NF
5	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp West	Bonneville Power Administration	NF
6	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp East	Sierra Pacific Power	NF
7	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp East	Sierra Pacific Power	SFP
8	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp West	PacifiCorp East	NF
9	Powerex Corp. (INCLUDES REDIRECTS)	NorthWestern/PacifiCorp East	PacifiCorp East	NF
10	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp West	Sierra Pacific Power	NF
11	Powerex Corp. (INCLUDES REDIRECTS)	PacifiCorp East	Bonneville Power Administration	NF
12	Powerex Corp. (INCLUDES REDIRECTS)	Bonneville Power Administration	Sierra Pacific Power	NF
13	Powerex Corp. (INCLUDES REDIRECTS)	Bonneville Power Administration	Sierra Pacific Power	SFP
14	Powerex Corp. (INCLUDES REDIRECTS)	Seattle City Light	Sierra Pacific Power	NF
15	Powerex Corp. (INCLUDES REDIRECTS)	Seattle City Light	Sierra Pacific Power	SFP
16	Powerex Corp. (INCLUDES REDIRECTS)			AD
17	PP & L Montana	NorthWestern/PacifiCorp East	PacifiCorp East	NF
18	PP & L Montana	Bonneville Power Administration	PacifiCorp West	NF
19	PP & L Montana	PacifiCorp East	PacifiCorp East	NF
20	PP & L Montana	NorthWestern/PacifiCorp East	PacifiCorp East	NF
21	PP & L Montana	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
22	PP & L Montana			AD
23	PPM Energy	PacifiCorp East	PacifiCorp East	NF
24	PPM Energy	Bonneville Power Administration	PacifiCorp West	NF
25	PPM Energy	PacifiCorp West	PacifiCorp East	NF
26	PPM Energy	PacifiCorp East	Bonneville Power Administration	NF
27	PPM Energy	PacifiCorp West	Bonneville Power Administration	NF
28	PPM Energy	Bonneville Power Administration	PacifiCorp East	NF
29	PPM Energy			AD
30	Puget Sound Energy	Sierra Pacific Power	Bonneville Power Administration	NF
31	Puget Sound Energy	PacifiCorp East	PacifiCorp East	NF
32	Puget Sound Energy	NorthWestern/PacifiCorp East	PacifiCorp East	NF
33	Puget Sound Energy			AD
34	Rainbow Energy Marketing Company	Avista	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) 04/11/2008	Year/Period of Report End of 2007/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
5	LOLO	BOBR		20,444	20,444	1
5	LOLO	M345		28,699	28,699	2
5	MLCK	BOBR		29,651	29,651	3
5	JBSN	M500		34,146	34,146	4
5	JBSN	LGBP		41,638	41,638	5
5	BOBR	M345		25,955	25,955	6
5	BOBR	M345		19,438	19,438	7
5	ENPR	BOBR		51,512	51,512	8
5	HTSP	BOBR		69,785	69,785	9
5	ENPR	M345		84,927	84,927	10
5	BOBR	LGBP		91,394	91,394	11
5	LGBP	M345		97,096	97,096	12
5	LGBP	M345		9,392	9,392	13
5	LYPK	M345		191,400	191,400	14
5	LYPK	M345		59,927	59,927	15
5						16
5	HTSP	BOBR		420	420	17
5	LGBP	JBSN		670	670	18
5	MLCK	BOBR		1,647	1,647	19
5	HTSP	BOBR		1,800	1,800	20
5	JEFF	LGBP		2,798	2,798	21
5						22
5	MLCK	BOBR		76	76	23
5	LGBP	JBSN		154	154	24
5	ENPR	BOBR		373	373	25
5	BOBR	LGBP		771	771	26
5	JBSN	LGBP		1,089	1,089	27
5	LGBP	BOBR		1,920	1,920	28
5						29
5	M345	LGBP		50	50	30
5	MLCK	BOBR		135	135	31
5	HTSP	BOBR		21,758	21,758	32
5						33
5	LOLO	M345		32	32	34
			0	**4,052,567**	**4,052,567**	

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

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

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

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
5	JEFF	LGBP		400	400	1
5	HTSP	BOBR		2,400	2,400	2
5	LGBP	M345		47,646	47,646	3
5	ENPR	M345		2,833	2,833	4
5	HTSP	BOBR		3,915	3,915	5
5	HTSP	BOBR		633	633	6
5	ENPR	BOBR		4,633	4,633	7
5	LGBP	BOBR		6,080	6,080	8
5	LOLO	BOBR		11,389	11,389	9
5	LGBP	M345		11,973	11,973	10
5	LOLO	M345		12,688	12,688	11
5						12
5	M345	LOLO		50	50	13
5	JEFF	BOBR		155	155	14
5	LOLO	BOBR		280	280	15
5	IPCO	LGBP		400	400	16
5	LGBP	BOBR		715	715	17
5	M345	LGBP		735	735	18
5	JBSN	BOBR		866	866	19
5	MLCK	BOBR		2,550	2,550	20
5	HTSP	M345		3,170	3,170	21
5	ENPR	M345		10,355	10,355	22
5	HTSP	BOBR		25,006	25,006	23
5	JBSN	M345		48,050	48,050	24
5	LGBP	M345		100,113	100,113	25
5	LGBP	M345		1,520	1,520	26
5	JEFF	M345		115,858	115,858	27
5	LOLO	M345		131,907	131,907	28
5	BOBR	M345		129,715	129,715	29
5	BOBR	M345		47,901	47,901	30
5						31
5						32
5	BOBR	M345		152	152	33
						34
			0	**4,052,567**	**4,052,567**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
1,351,834	-14,828		1,337,006	1
-72,555			-72,555	2
1,148,212	1,654		1,149,866	3
-34,997			-34,997	4
654,366	-92,085		562,281	5
-39,784			-39,784	6
2,507,720	-31,654		2,476,066	7
-163,835			-163,835	8
	14,073		14,073	9
		4,860	4,860	10
7,283	1,624		8,907	11
-371			-371	12
54,185			54,185	13
	-437,356		-437,356	14
	20,114		20,114	15
	313,865		313,865	16
	57		57	17
	171		171	18
	183		183	19
	5,545		5,545	20
	10,536		10,536	21
	19,971		19,971	22
	-7,729		-7,729	23
	17		17	24
	1,625		1,625	25
	-405		-405	26
	64		64	27
	531		531	28
	1,683		1,683	29
	3,278		3,278	30
	5,340		5,340	31
	8,318		8,318	32
	8,346		8,346	33
	82,036		82,036	34
5,412,058	**10,812,173**	**4,860**	**16,229,091**	

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	04/11/2008	End of 2007/Q4

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	-155		-155	1
	107		107	2
	150		150	3
	215		215	4
	245		245	5
	253		253	6
	292		292	7
	537		537	8
	1,443		1,443	9
	1,907		1,907	10
	2,913		2,913	11
	3,548		3,548	12
	3,630		3,630	13
	7,071		7,071	14
	10,082		10,082	15
	26,208		26,208	16
	53,378		53,378	17
	75,888		75,888	18
	98,728		98,728	19
	124,111		124,111	20
	135,293		135,293	21
	255,057		255,057	22
	496,204		496,204	23
	565,901		565,901	24
	840,826		840,826	25
	119,012		119,012	26
	-70,304		-70,304	27
	650		650	28
	1,300		1,300	29
	336		336	30
	790		790	31
	265		265	32
	430		430	33
	437		437	34
5,412,058	**10,812,173**	**4,860**	**16,229,091**	

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	04/11/2008	End of 2007/Q4

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	546		546	1
	2,250		2,250	2
	8,183		8,183	3
	13		13	4
	293		293	5
	101		101	6
	182		182	7
	1,086		1,086	8
	1,362		1,362	9
	1,439		1,439	10
	1,706		1,706	11
	2,399		2,399	12
	2,687		2,687	13
	5,155		5,155	14
	10,840		10,840	15
	11,177		11,177	16
	12,871		12,871	17
	16,108		16,108	18
	22,625		22,625	19
	29,372		29,372	20
	-65,646		-65,646	21
	562		562	22
	51,780		51,780	23
	201,841		201,841	24
	320,156		320,156	25
	475,223		475,223	26
	222,289		222,289	27
	754,483		754,483	28
	-68,812		-68,812	29
	284		284	30
	1,368		1,368	31
	1,389		1,389	32
	1,556		1,556	33
	4,378		4,378	34
5,412,058	**10,812,173**	**4,860**	**16,229,091**	

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	04/11/2008	End of 2007/Q4

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	8,066		8,066	1
	17,495		17,495	2
	-131		-131	3
	89		89	4
	97		97	5
	101		101	6
	483		483	7
	543		543	8
	704		704	9
	789		789	10
	869		869	11
	869		869	12
	1,067		1,067	13
	1,179		1,179	14
	1,851		1,851	15
	2,000		2,000	16
	2,660		2,660	17
	3,498		3,498	18
	3,735		3,735	19
	3,795		3,795	20
	4,665		4,665	21
	5,132		5,132	22
	5,317		5,317	23
	5,486		5,486	24
	5,675		5,675	25
	8,339		8,339	26
	12,561		12,561	27
	16,952		16,952	28
	17,854		17,854	29
	19,573		19,573	30
	21,991		21,991	31
	25,392		25,392	32
	31,043		31,043	33
	51,509		51,509	34
5,412,058	**10,812,173**	**4,860**	**16,229,091**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	82,283		82,283	1
	115,508		115,508	2
	119,339		119,339	3
	137,431		137,431	4
	167,584		167,584	5
	104,464		104,464	6
	78,234		78,234	7
	207,325		207,325	8
	280,870		280,870	9
	341,814		341,814	10
	367,842		367,842	11
	390,792		390,792	12
	37,801		37,801	13
	770,346		770,346	14
	241,194		241,194	15
	-91,770		-91,770	16
	1,334		1,334	17
	2,128		2,128	18
	5,232		5,232	19
	5,718		5,718	20
	8,888		8,888	21
	-3,726		-3,726	22
	427		427	23
	865		865	24
	2,095		2,095	25
	4,330		4,330	26
	6,117		6,117	27
	10,784		10,784	28
	-4,040		-4,040	29
	201		201	30
	542		542	31
	87,367		87,367	32
	-155		-155	33
	100		100	34
5,412,058	**10,812,173**	**4,860**	**16,229,091**	

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.
	1,255		1,255	1
	7,528		7,528	2
	149,444		149,444	3
	21,095		21,095	4
	29,152		29,152	5
	4,713		4,713	6
	34,499		34,499	7
	45,273		45,273	8
	84,806		84,806	9
	89,154		89,154	10
	94,478		94,478	11
	-65,318		-65,318	12
	159		159	13
	493		493	14
	891		891	15
	1,273		1,273	16
	2,275		2,275	17
	2,338		2,338	18
	2,755		2,755	19
	8,113		8,113	20
	10,085		10,085	21
	32,944		32,944	22
	79,555		79,555	23
	152,868		152,868	24
	318,503		318,503	25
	4,836		4,836	26
	368,594		368,594	27
	419,653		419,653	28
	412,679		412,679	29
	152,394		152,394	30
	-118,313		-118,313	31
	-60		-60	32
	579		579	33
				34
5,412,058	**10,812,173**	**4,860**	**16,229,091**	

Schedule Page: 328 Line No.: 1 Column: e

This footnote applies to all Rate schedule or Tariff number in column E that are listed as a number 5. Number 5 indicates 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

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.: 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

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 transmissin system peak and varies by month.

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

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.: 7 Column: h

The network service agreement between Idaho Power and the Bonneville Power Administaration 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

The network service agreement between Idaho Power and the Bonnevill Power Administratin 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.: 9 Column: e

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, 2007.

Schedule Page: 328 Line No.: 10 Column: e

Contract prior to the Open Access Transmission Tariff.

Schedule Page: 328 Line No.: 10 Column: h

The agreement between Idaho Power and the City of Seattle expires December 31, 2007.

Schedule Page: 328 Line No.: 10 Column: m

Monthly Customer Charge.

Name of Respondent Idaho Power Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report 2007/Q4

FOOTNOTE DATA

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

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

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

Contract prior to the Open Access Transmissin 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

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 Transmissin Service Agreement (RSTA) FERC filing 3/9/92.

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

Contract prior to the Open Access Transmission Tariff.

Schedule Page: 328 Line No.: 15 Column: h

The contract between Idaho Power and PacifiCorp is for the life of Bridger project per 1992 Restated Transmission Service Agreement (RTSA) FERC filing 3/9/92.

Schedule Page: 328 Line No.: 16 Column: e

Contract prior to the Open Access Transmission Tariff.

Schedule Page: 328 Line No.: 16 Column: h

The contract between Idaho Power and PacifiCorp is for the life of Bridger project per 1992 Reatated Transmission Service Agreement (RTSA) FERC filing 3/9/92.

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	04/11/2008	End of 2007/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Avista Corp - WWp Div	NF	197,176	197,176		831,466		831,466
2	Avista Corp - WWP Div	SFP	338,223	338,223		828,659		828,659
3	Bonneville Power Admin	LFP	520,163	520,163	1,225,632			1,225,632
4	Bonneville Power Admin	LFP			53,892			53,892
5	Bonneville Power Admin	NF	58,901	58,901		310,072		310,072
6	Bonneville Power Admin	SFP	544,201	544,201		1,694,950		1,694,950
7	Bonneville Power Admin	OS					16,794	16,794
8	Morgan Stanley Cap Grp	NF	10,688	10,688		30,520		30,520
9	Northwestern Energy	NF	10,596	10,596		55,467		55,467
10	NorthWesern Energy	SFP	121,244	121,244		785,298		785,298
11	NorthWestern Energy	LFP	109,355	109,355	211,079	18,462		229,541
12	PacifiCorp Inc.	NF	392,993	392,993		1,759,729		1,759,729
13	PacifiCorp Inc.	SFP	282,349	282,349		1,126,212		1,126,212
14	PacifiCorp Inc.	LFP	24,675	24,675		759,375		759,375
15	PacifiCorp Inc.	OS					2,819	2,819
16	PPL Montana LLC	NF					-26,660	-26,660
	TOTAL		2,900,708	2,900,708	1,490,603	9,040,462	-61,339	10,469,726

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	04/11/2008	End of 2007/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Seattle City Light	NF	47,749	47,749		166,751		166,751
2	Sierra Pacific Power Co	NF	3,282	3,282		16,699		16,699
3	Sierra Pacific Power Co	SFP	521	521		8,393		8,393
4	Snohomish County PUD	NF	187,373	187,373		476,661		476,661
5	Tacoma Power	NF	51,219	51,219		171,748		171,748
6	TransAlta Energy Markt	NF					-49,740	-49,740
7	United Mat Great Falls	NF					-4,552	-4,552
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		2,900,708	2,900,708	1,490,603	9,040,462	-61,339	10,469,726

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Schedule Page: 332 Line No.: 3 Column: b

Contract expires on 9/30/2016.

Schedule Page: 332 Line No.: 4 Column: b

Contract expires on 7/16/2011.

Schedule Page: 332 Line No.: 7 Column: g

Unauthorized increase charge.

Schedule Page: 332 Line No.: 11 Column: b

Contract can be terminated at anytime, with 30 days prior notice.

Schedule Page: 332 Line No.: 14 Column: b

Contract expires on 6/1/2009.

Schedule Page: 332 Line No.: 15 Column: g

Transmission Study Fee.

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

Resale Transmission.

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

Resale Transmission.

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

Resale Transmission.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2008	End of 2007/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	362,971
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	270,020
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	1,215,390
6	Rotchford Barker	17,596
7	Christine King	34,720
8	Jon Miller	76,453
9	Gary Michael	60,352
10	Richard Reiten	34,571
11	Joan Smith	47,718
12	Jan Packwood	31,600
13	Judith Johansen	29,963
14	Peter O'neill	48,333
15	Thomas Wilford	44,125
16	Robert Tintsman	47,488
17	Chambers of Commerce & Other Civic Organizations	85,610
18		
19	Associated Taxpayers of Idaho	21,252
20	Association of Idaho Cities	750
21	Corporate Executive Board	146,095
22	Eastern Oregon Vsisitor Association	1,125
23	Idaho Association of Counties	2,250
24	Idaho Association of Commerce and Industry	10,000
25	Idaho Economic Development Association	1,000
26	Idaho Mining Association	2,640
27	Idaho Water Users	1,200
28	Misc Memberships (6)	5,320
29	National HydroPower Assoc	23,602
30	Pacific NW Utilities	35,810
31	The Conference Board	2,850
32	Utility Wind Interest Group	5,000
33	West Associates	22,580
34	Western Electricity Coordiniating Council	759,871
35	Wyoming Taxpayers Assoc	1,500
36		
37	Miscellaneous General Management:	
38	New York Stock Exchange	37,461
39	PR Newswire	9,942
40		
41		
42		
43		
44		
45		
46	TOTAL	3,497,158

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

Recipient	Purpose	Amount
Pete Wilson Design	Annual Report	$ 7,737
Deutsche Bank	Broker Fees	427,127
Deutsche Bank Trust	Fee Humbolt County	16,630
Georgeson Shareholder	Letter of Agreement	62,595
Global Insight	Data Subscription	25,662
Option Expense	Directors Rest Stock	41,564
Port of Morrow	Port of Morrow Bond	5,475
Union Bank of Calif	Sweetwater & PC Bonds	10,260
Wells Fargo S/o Service	Wells Fargo Transfer	140,157
Broadridge Finc Solutions	Proxy & Bulletin svc	51,211
Shareholder.com	Shareholder Webcasting	14,727
Thompson Financial	Analyst Service	15,300
Workorder Change Adj		489,288
Other itmes under $5,000	Misc	-92,343
Total		$ 1,215,390

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

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

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

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			8,095,753		8,095,753
2	Steam Production Plant	24,012,280				24,012,280
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	12,809,053				12,809,053
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	3,044,614				3,044,614
7	Transmission Plant	13,722,782				13,722,782
8	Distribution Plant	29,220,567				29,220,567
9	Regional Transmission and Market Operation					
10	General Plant	12,486,203				12,486,203
11	Common Plant-Electric	-296,299				-296,299
12	TOTAL	94,999,200		8,095,753		103,094,953

B. Basis for Amortization Charges

Account 404

	Balance to be Amortized	2007 Amortization	Balance to be amortized 12/31/07	Remaining months of amortization 12/31/07
(1)	12,000	12,000	60,000	60
(2)	13,283,905	480,871	12,803,025	-
(3)	13,726,109	7,310,611	13,801,327	-
(4)	222,578	4,084	-	218
(5)	6,051,936	288,187	5,763,749	240
TOTAL	33,296,528	8,095,753	32,428,100	

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

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	310.00	203	75.00		2.27	R4.0	19.20
13	311.00	131,444	90.00	-10.00	2.59	S1.0	18.30
14	312.10	77,341	55.00	-10.00	2.76	R3.0	19.10
15	312.20	443,170	70.00	-10.00	2.89	R1.5	18.10
16	312.30	4,208	25.00	20.00	2.77	R3.0	16.40
17	314.00	126,934	50.00	-10.00	3.46	S0.5	17.20
18	315.00	61,606	65.00		2.16	S1.5	17.80
19	316.00	13,023	45.00		3.07	R0.5	16.40
20	316.10	59	9.00	25.00	1.78	L3.0	9.00
21	316.40	226	9.00	25.00	3.44	L3.0	5.40
22	316.50	124	9.00	25.00	8.45	L3.0	3.50
23	316.70	80	17.00	25.00	4.26	S2.5	8.10
24	316.80	1,115	14.00	35.00	7.01	L0.5	9.40
25	317.000	4,731					
26	Subtotal Steam	864,264					
27	331.00	145,330	100.00	-20.00	2.37	S1.0	36.80
28	332.10	19,460	85.00	-10.00	1.93	S4.0	31.40
29	332.20	220,997	85.00	-10.00	1.93	S4.0	34.10
30	332.30	5,600	69.00		1.44	SQUARE	63.60
31	333.00	187,856	80.00	-5.00	1.83	R3.0	38.00
32	334.00	37,537	47.00		2.85	R1.5	28.00
33	335.00	16,325	100.00		1.86	S0.0	34.90
34	336.00	7,493	75.00		1.95	R3.0	34.70
35	Subtotal Hydro	640,598					
36	341.00	5,697	35.00		2.84	SQUARE	34.50
37	342.00	3,766	35.00		2.83	SQUARE	33.90
38	343.00	43,597	35.00		2.88	SQUARE	34.50
39	344.00	36,682	35.00		2.84	SQUARE	34.50
40	345.00	14,056	35.00		2.79	SQUARE	34.50
41	346.00	2,258	35.00		2.88	SQUARE	34.50
42	Subtotal Other	106,056					
43	350.20	24,453	65.00		1.54	R3.0	52.30
44	350.21	4,063	24.00		4.09	SQUARE	24.00
45	352.00	40,254	60.00	-20.00	1.29	R3.0	48.00
46	353.00	262,978	45.00	-5.00	2.12	S0.5	32.70
47	354.00	121,742	60.00	-30.00	2.45	S4.0	37.30
48	355.00	88,361	55.00	-60.00	2.94	R2.0	39.90
49	356.00	139,652	60.00	-20.00	1.96	R2.0	41.40
50	359.00	318	65.00		1.07	R3.0	27.00

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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	Subtotal Transmission	681,821					
13	361.00	21,657	55.00	-20.00	2.05	R2.5	40.70
14	362.00	151,683	50.00		1.64	O1.0	43.60
15	364.00	203,942	41.00	-50.00	3.67	R1.5	29.80
16	365.00	106,512	46.00	-30.00	3.25	R2.0	29.50
17	366.00	46,129	60.00	-25.00	2.04	R2.0	51.90
18	367.00	171,154	37.00	-10.00	2.73	S1.5	28.60
19	368.00	352,642	35.00	5.00	1.73	R2.0	27.10
20	369.00	53,888	30.00	-30.00	3.69	S2.0	20.50
21	370.00	56,323	30.00		4.06	L2.0	19.70
22	371.10	359	8.00		28.42	S5.0	2.30
23	371.20	2,374	11.00	-20.00	11.85	R0.5	7.00
24	373.00	4,121	20.00	-20.00	5.75	R1.0	10.90
25	374.00	259					
26	Subtotal Distribution	1,171,043					
27	390.11	26,486	100.00	-5.00	2.27	S1.5	38.50
28	390.12	33,804	50.00	-5.00	2.17	R3.0	36.00
29	390.20	8,590	25.00		3.85	S3.0	16.90
30	391.10	13,173	20.00		9.66	SQUARE	7.70
31	391.20	22,563	5.00		20.00	SQUARE	5.00
32	391.21	2,460	6.00		16.67	S5.0	6.00
33	392.10	356	9.00	25.00	1.78	L3.0	7.90
34	392.30	2,580	15.00	50.00	3.79	S2.0	15.00
35	392.40	19,739	9.00	25.00	3.45	L3.0	6.90
36	392.50	578	9.00	25.00	9.45	L3.0	9.00
37	392.60	25,961	17.00	25.00	4.72	S2.5	10.20
38	392.70	4,150	17.00	25.00	4.26	S2.5	7.90
39	392.90	3,892	30.00	25.00	1.93	S1.0	21.90
40	393.00	1,075	25.00		7.89	SQUARE	8.70
41	394.00	4,410	20.00		8.31	SQUARE	8.10
42	395.00	10,232	20.00		6.53	SQUARE	9.80
43	396.00	8,710	14.00	35.00	6.99	L0.5	7.70
44	397.10	6,090	15.00		11.61	SQUARE	5.70
45	397.20	15,453	15.00		9.99	SQUARE	7.40
46	397.30	2,894	15.00		9.99	SQUARE	6.70
47	397.40	1,458	10.00		16.45	SQUARE	5.20
48	398.00	3,026	15.00		8.50	SQUARE	8.80
49	Subtotal General	217,680					
50	Total Plant	3,681,462					

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	04/11/2008	End of 2007/Q4

REGULATORY COMMISSION EXPENSES

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

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Federal Energy Regulatory Commission:				
2	Annual admin charges assessed by FERC	2,980,908		2,980,908	
3					
4	General Regulatory Expenses and				
5	Various other Dockets		2,455,978	2,455,978	
6					
7	Regulatory Commission Expenses - Idaho				
8	Expenses and various other Dockets		250,641	250,641	
9					
10	Oregon Hydro - Fees Amortization	158,506		158,506	
11					
12	Regulatory Commission Expenses - Oregon				
13	Expenses and various other Dockets		184,221	184,221	
14					
15					
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40					
41					
42					
43					
44					
45					
46	TOTAL	3,139,414	2,890,840	6,030,254	

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			Deferred to Account 182.3	Contra Account	Amount	Deferred in Account 182.3 End of Year	Line No.
Department (f)	Account No. (g)	Amount (h)	(i)	(j)	(k)	(l)	
							1
Electric	928	2,980,908					2
							3
Electric	928	2,455,978					4
							5
							6
Electric	928	250,641					7
							8
							9
Electric	928	158,506					10
							11
Electric	928	184,221					12
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							14
							15
							16
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							45
		6,030,254					46

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

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

Classifications:

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

Line No.	Classification (a)	Description (b)
1	A. Electric R, D & D Performed internally:	
2	(1) Generation	
3	e. unconventional generation	Air Conditioning Cool Credit
4		Appliance Program
5		Change a Light Spring 2007
6		Energy House Calls
7		Irrigation Peak Rewards
8		Energy Star Northwest Homes
9		Heating & Cooling Efficiency
10		Oregon Weatherization
11		Rebate Advantage
12		Residential Retrofit - Lighting
13		Savings with a Twist 2006
14		Weatherization Asistance Idaho
15		Building Efficiency Program
16		Easy Upgrades - Commercial
17		Oregon Commercial Audit
18		Industrial Custom Efficiency
19		Irrigation Efficiency Rewards Program
20		NEEA
21		Commercial Education Initiative
22		Other C&RD/CRC Renewable
23		Distribution Efficiency Initiative
24		Small Project/Education funds
25		DSM Analysis & Accounting
26		DSM Direct Program Overhead
27		Energy Efficiency Advisory Group
28		Other
29		
30		
31		
32	Total R, D&D	
33		
34		
35		
36		
37		

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

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

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

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
					2
2,426,154			2,426,154		3
9,275			9,275		4
232,331			232,331		5
336,372			336,372		6
1,615,881			1,615,881		7
475,044			475,044		8
488,211			488,211		9
3,781			3,781		10
89,269			89,269		11
316,218			316,218		12
9,096			9,096		13
1,323,624			1,323,624		14
669,032			669,032		15
711,494			711,494		16
1,981			1,981		17
3,161,866			3,161,866		18
2,001,961			2,001,961		19
893,340			893,340		20
26,823			26,823		21
31,645			31,645		22
8,987			8,987		23
7,520			7,520		24
732,503			732,503		25
56,909			56,909		26
2,597			2,597		27
30,462			30,462		28
					29
					30
					31
15,662,376			15,662,376		32
					33
					34
					35
					36

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	13,189,520		
4	Transmission	6,543,851		
5	Regional Market			
6	Distribution	16,770,868		
7	Customer Accounts	9,966,870		
8	Customer Service and Informational	3,873,259		
9	Sales			
10	Administrative and General	36,636,627		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	86,980,995		
12	Maintenance			
13	Production	6,106,207		
14	Transmission	2,323,590		
15	Regional Market			
16	Distribution	7,064,886		
17	Administrative and General	831,088		
18	TOTAL Maintenance (Total of lines 13 thru 17)	16,325,771		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	19,295,727		
21	Transmission (Enter Total of lines 4 and 14)	8,867,441		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	23,835,754		
24	Customer Accounts (Transcribe from line 7)	9,966,870		
25	Customer Service and Informational (Transcribe from line 8)	3,873,259		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	37,467,715		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	103,306,766		103,306,766
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			

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	103,306,766		103,306,766
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	46,687,930	3,994,960	50,682,890
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	46,687,930	3,994,960	50,682,890
72	Plant Removal (By Utility Departments)			
73	Electric Plant			
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)			
77	Other Accounts (Specify, provide details in footnote):			
78	Paid Absences	17,092,558		17,092,558
79	Preliminary Survey & Investigations	72,706		72,706
80	Other Accounts	6,811,728		6,811,728
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	23,976,992		23,976,992
96	TOTAL SALARIES AND WAGES	173,971,688	3,994,960	177,966,648

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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	04/11/2008	End of 2007/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

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

NAME OF SYSTEM: 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	3,042	18	8	1,812	218	538		474	
2	February	2,993	2	8	1,705	204	538		546	
3	March	2,708	1	8	1,443	188	538		539	
4	Total for Quarter 1	8,743			4,960	610	1,614		1,559	
5	April	2,593	30	14	1,463	196	580		354	
6	May	3,327	31	19	2,209	274	580		264	
7	June	3,873	28	16	2,661	324	580		308	
8	Total for Quarter 2	9,793			6,333	794	1,740		926	
9	July	4,079	13	16	2,868	322	580		309	
10	August	3,733	16	18	1,817	289	580		1,047	
11	September	3,509	3	18	1,530	251	580		1,148	
12	Total for Quarter 3	11,321			6,215	862	1,740		2,504	
13	October	2,456	11	8	292	154	580		1,430	
14	November	2,874	28	8	1,969	185	580		140	
15	December	2,996	10	19	1,862	191	580		363	
16	Total for Quarter 4	8,326			4,123	530	1,740		1,933	
17	Total Year to Date/Year	38,183			21,631	2,796	6,834		6,922	

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	04/11/2008	End of 2007/Q4

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	14,541,825
3	Steam	7,144,279	23	Requirements Sales for Resale (See instruction 4, page 311.)	57,436
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	2,686,211
5	Hydro-Conventional	6,181,322	25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
7	Other	222,410	27	Total Energy Losses	1,258,845
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	18,544,317
9	Net Generation (Enter Total of lines 3 through 8)	13,548,011			
10	Purchases	5,195,964			
11	Power Exchanges:				
12	Received	104,827			
13	Delivered	293,024			
14	Net Exchanges (Line 12 minus line 13)	-188,197			
15	Transmission For Other (Wheeling)				
16	Received	4,052,567			
17	Delivered	4,064,028			
18	Net Transmission for Other (Line 16 minus line 17)	-11,461			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	18,544,317			

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	04/11/2008	End of 2007/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 on line 2 by month the system's output in Megawatt hours for each month.
(3) Report on line 3 by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
(4) Report on line 4 by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
(5) Report on lines 5 and 6 the specified information for each monthly peak load reported on line 4.

NAME OF SYSTEM: Idaho Power Company

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	1,745,492	363,384	2,422	16	8 AM
30	February	1,318,828	211,820	2,268	2	8 AM
31	March	1,463,248	372,625	2,023	1	7 PM
32	April	1,297,582	212,871	1,937	30	6 PM
33	May	1,455,149	92,335	2,484	31	7 PM
34	June	1,736,261	207,301	3,009	28	6 PM
35	July	1,991,363	175,571	3,193	13	4 PM
36	August	1,806,531	205,281	2,904	1	7 PM
37	September	1,462,172	226,921	2,695	3	7 PM
38	October	1,343,230	232,723	1,838	31	8 AM
39	November	1,317,419	145,751	2,130	30	8 AM
40	December	1,607,042	239,628	2,287	11	8 AM
41	TOTAL	18,544,317	2,686,211			

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	04/11/2008	End of 2007/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	Plant Name: *Jim Bridger* (b)			Plant Name: *Boardman* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Semi-Outdoor Boiler			Conventional		
3	Year Originally Constructed	1974			1980		
4	Year Last Unit was Installed	1979			1980		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	770.50			64.22		
6	Net Peak Demand on Plant - MW (60 minutes)	716			60		
7	Plant Hours Connected to Load	8759			7703		
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	5027859000			436616000		
13	Cost of Plant: Land and Land Rights	494358			106610		
14	Structures and Improvements	63385775			13754891		
15	Equipment Costs	397769026			55799812		
16	Asset Retirement Costs	0			0		
17	Total Cost	461649159			69661313		
18	Cost per KW of Installed Capacity (line 17/5) Including	599.1553			1084.7293		
19	Production Expenses: Oper, Supv, & Engr	142655			833210		
20	Fuel	72804161			6291429		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	4043307			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	6132445			253061		
27	Rents	247399			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	290118			2288516		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	8049032			0		
32	Maintenance of Electric Plant	2707127			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	5623393			16285		
34	Total Production Expenses	100039637			9682501		
35	Expenses per Net KWh	0.0199			0.0222		
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	2855550	21655	0	261586	617	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	9096	140000	0	8357	138800	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	24.015	97.825	0.000	23.746	93.920	0.000
41	Average Cost of Fuel per Unit Burned	24.020	68.725	0.000	22.522	89.275	0.000
42	Average Cost of Fuel Burned per Million BTU	1.324	11.688	0.000	1.364	15.308	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.014	0.000	0.000	0.014	0.000	0.000
44	Average BTU per KWh Net Generation	10330.000	0.000	0.000	9901.000	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	04/11/2008	End of 2007/Q4

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

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

Plant Name: *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			91.80			172.80			5
288			94			192			6
8561			567			1219			7
0			90471			164159			8
0			0			0			9
0			0			0			10
0			7			4			11
167984000			38346000			183930000			12
769351			402745			0			13
54302963			4276833			1388528			14
274317434			47594392			51875802			15
0			0			0			16
329389748			52273970			53264330			17
1161.8686			569.4332			308.2427			18
689008			158224			40876			19
35741649			4436961			15019887			20
0			0			0			21
2796802			0			0			22
0			0			0			23
0			0			0			24
2109888			182179			196417			25
1682728			133555			144253			26
48376			0			0			27
0			0			0			28
1613			0			0			29
649264			128229			90697			30
6581028			18979			3525			31
2978251			418715			158696			32
295173			0			0			33
53573780			5476842			15654351			34
0.3189			0.1428			0.0851			35
Coal	Oil		Gas			Gas			36
Tons	Barrels		MCF			MCF			37
817341	7610	0	580326	0	0	1859933	0	0	38
9689	138778	0	1038	0	0	1038	0	0	39
40.917	105.774	0.000	7.646	0.000	0.000	8.076	0.000	0.000	40
41.108	103.332	0.000	7.646	0.000	0.000	8.076	0.000	0.000	41
2.081	17.727	0.000	7.366	0.000	0.000	7.780	0.000	0.000	42
0.021	0.000	0.000	0.116	0.000	0.000	0.082	0.000	0.000	43
9638.000	0.000	0.000	15709.000	0.000	0.000	10496.000	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	04/11/2008	End of 2007/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 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)	88	68
7	Plant Hours Connect to Load	6,868	8,753
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	109	76
10	(b) Under the Most Adverse Oper Conditions	0	1
11	Average Number of Employees	4	4
12	Net Generation, Exclusive of Plant Use - Kwh	262,405,000	318,932,000
13	Cost of Plant		
14	Land and Land Rights	875,318	676,645
15	Structures and Improvements	11,974,476	719,557
16	Reservoirs, Dams, and Waterways	4,293,075	8,186,692
17	Equipment Costs	31,152,568	7,072,055
18	Roads, Railroads, and Bridges	839,276	486,477
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	49,134,713	17,141,426
21	Cost per KW of Installed Capacity (line 20 / 5)	532.3371	228.5523
22	Production Expenses		
23	Operation Supervision and Engineering	175,578	614,245
24	Water for Power	2,002,227	169,300
25	Hydraulic Expenses	105,920	461,767
26	Electric Expenses	40,511	45,533
27	Misc Hydraulic Power Generation Expenses	256,085	164,574
28	Rents	152	2,969
29	Maintenance Supervision and Engineering	104,858	105,578
30	Maintenance of Structures	82,178	42,046
31	Maintenance of Reservoirs, Dams, and Waterways	4,547	26,534
32	Maintenance of Electric Plant	187,945	120,220
33	Maintenance of Misc Hydraulic Plant	148,018	101,091
34	Total Production Expenses (total 23 thru 33)	3,108,019	1,853,857
35	Expenses per net KWh	0.0118	0.0058

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	04/11/2008	End of 2007/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

FERC Licensed Project No. 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
635	12	218	6
8,760	8,638	8,760	7
			8
747	15	221	9
220	1	202	10
7	2	6	11
1,828,216,000	37,158,000	782,019,000	12
			13
17,086,224	82,142	1,137,645	14
30,545,607	7,364,154	9,974,169	15
66,925,091	3,145,630	30,375,714	16
51,770,609	12,733,856	15,230,301	17
518,444	122,668	565,842	18
0	0	0	19
166,845,975	23,448,450	57,283,671	20
285.0119	1,887.9589	301.4930	21
			22
545,976	133,673	276,741	23
154,784	104,795	72,024	24
677,644	231,329	327,120	25
362,369	82,658	200,901	26
414,223	172,312	224,199	27
231,040	110	39,673	28
351,817	92,000	269,736	29
144,385	11,200	310,949	30
53,887	14,008	158,676	31
457,981	132,808	134,363	32
510,214	84,150	400,134	33
3,904,320	1,059,043	2,414,516	34
0.0021	0.0285	0.0031	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	04/11/2008	End of 2007/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 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)	405	26
7	Plant Hours Connect to Load	8,760	8,760
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	445	25
10	(b) Under the Most Adverse Oper Conditions	137	21
11	Average Number of Employees	5	1
12	Net Generation, Exclusive of Plant Use - Kwh	1,560,339,000	163,575,000
13	Cost of Plant		
14	Land and Land Rights	1,558,955	205,376
15	Structures and Improvements	2,403,495	2,516,767
16	Reservoirs, Dams, and Waterways	52,511,953	3,531,422
17	Equipment Costs	15,117,778	3,378,169
18	Roads, Railroads, and Bridges	819,192	304,683
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	72,411,373	9,936,417
21	Cost per KW of Installed Capacity (line 20 / 5)	184.9588	456.4271
22	Production Expenses		
23	Operation Supervision and Engineering	274,365	101,726
24	Water for Power	73,903	519,539
25	Hydraulic Expenses	312,773	113,376
26	Electric Expenses	131,879	62,926
27	Misc Hydraulic Power Generation Expenses	240,367	62,154
28	Rents	66,279	0
29	Maintenance Supervision and Engineering	225,473	57,416
30	Maintenance of Structures	61,720	48,213
31	Maintenance of Reservoirs, Dams, and Waterways	86,692	5,197
32	Maintenance of Electric Plant	130,349	47,500
33	Maintenance of Misc Hydraulic Plant	614,676	75,005
34	Total Production Expenses (total 23 thru 33)	2,218,476	1,093,052
35	Expenses per net KWh	0.0014	0.0067

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	04/11/2008	End of 2007/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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

Line No.	Item (a)	FERC Licensed Project No. 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)	39	13
7	Plant Hours Connect to Load	8,760	5,546
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	226,157,000	55,613,000
13	Cost of Plant		
14	Land and Land Rights	172,970	311,407
15	Structures and Improvements	1,546,638	1,199,262
16	Reservoirs, Dams, and Waterways	4,777,191	512,402
17	Equipment Costs	6,437,887	2,315,859
18	Roads, Railroads, and Bridges	29,359	51,383
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	12,964,045	4,390,313
21	Cost per KW of Installed Capacity (line 20 / 5)	375.7694	351.2250
22	Production Expenses		
23	Operation Supervision and Engineering	351,438	131,564
24	Water for Power	60,683	34,510
25	Hydraulic Expenses	276,909	137,674
26	Electric Expenses	19,882	12,568
27	Misc Hydraulic Power Generation Expenses	169,612	69,950
28	Rents	0	29
29	Maintenance Supervision and Engineering	97,478	116,802
30	Maintenance of Structures	80,176	154,659
31	Maintenance of Reservoirs, Dams, and Waterways	33,990	3,759
32	Maintenance of Electric Plant	126,595	29,785
33	Maintenance of Misc Hydraulic Plant	98,962	64,942
34	Total Production Expenses (total 23 thru 33)	1,315,725	756,242
35	Expenses per net KWh	0.0058	0.0136

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

FERC Licensed Project No. 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
85	22	39	6
8,758	8,759	8,571	7
			8
91	24	53	9
84	14	50	10
7	4	5	11
390,080,000	117,791,000	87,588,000	12
			13
3,302,043	51,675	255,499	14
2,892,897	25,232,769	10,808,047	15
10,033,408	13,856,887	7,932,716	16
7,418,814	30,378,323	20,598,630	17
248,183	835,946	1,917,603	18
0	0	0	19
23,895,345	70,355,600	41,512,495	20
288.5911	2,814.2240	787.1159	21
			22
887,694	295,748	217,274	23
243,786	71,831	50,130	24
1,240,232	272,165	125,511	25
31,576	28,026	42,004	26
328,197	145,994	146,282	27
67,657	7,843	1,098	28
164,237	67,429	33,919	29
101,516	59,448	32,048	30
68,828	61,827	3,749	31
182,046	68,838	59,769	32
208,808	101,617	58,604	33
3,524,577	1,180,766	770,388	34
0.0090	0.0100	0.0088	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	04/11/2008	End of 2007/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

FERC Licensed Project No. 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	47	40	6
0	8,760	6,400	7
			8
0	64	61	9
0	60	1	10
0	7	1	11
0	214,615,000	66,918,000	12
			13
114,367	403,707	138,100	14
25,941,940	1,362,364	10,326,813	15
13,556,785	6,603,461	17,147,050	16
1,183,136	6,877,680	27,574,117	17
99,051	88,693	501,877	18
0	0	0	19
40,895,279	15,335,905	55,687,957	20
0.0000	255.5984	936.7192	21
			22
0	1,109,770	114,144	23
0	160,154	1,338,577	24
4,322,824	728,507	70,875	25
0	183,038	44,885	26
0	264,588	145,513	27
0	1,283	1,520	28
3,189	112,586	59,065	29
0	77,497	41,526	30
0	5,945	6,698	31
0	235,429	145,639	32
76,676	113,718	65,904	33
4,402,689	2,992,515	2,034,346	34
0.0000	0.0139	0.0304	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 Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

GENERATING PLANT STATISTICS (Small Plants)

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

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Hydro:					
2	Clear Lakes	1937	2.50	2.3	17,091	1,759,032
3	Thousand Springs	1912	8.80	6.2	52,825	4,730,494
4						
5						
6	Internal Combustion:					
7	Salmon Diesel (1)	1967	5.00	5.0	134	901,055
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11	(1) Salmon units are classified as standby.					
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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) 04/11/2008	Year/Period of Report End of 2007/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

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

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
703,613	78,458		55,138			2
537,556	117,552		71,484			3
						4
						5
						6
180,211				Diesel		7
						8
						9
						10
						11
						12
						13
						14
						15
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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) 04/11/2008	Year/Period of Report End of 2007/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Boardman	Slatt	500.00	500.00	S Tower	1.79		1
2								
3	Borah	Midpoint	345.00	500.00	S Tower	85.17		1
4	Jim Bridger	Goshen	345.00	345.00	S Tower	226.17		1
5	State Line	Midpoint	345.00	345.00	S Tower	76.08		2
6	Kinport	Borah	345.00	345.00	S Tower	27.31		1
7	Midpoint	Borah #1	345.00	345.00	H Wood	79.36		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	46.24		1
12	Midpoint	Hunt	230.00	230.00	S Tower	0.60		2
13	Brady	Antelope	230.00	230.00	H Wood	56.44		1
14	Brady	Treasureton	230.00	230.00	H Wood	0.13		1
15	Brady #1 & #2	Kinport	230.00	230.00	S Tower	18.02		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	72.72		1
18	Mora	Bowmont	138.00	230.00	S P Wood	9.86		1
19	Mora	Bowmont	138.00	230.00	H Wood	10.77		1
20	Jim Bridger	Point of Rocks	230.00	230.00	H Wood	2.79		1
21	Caldwell 710	Locust	230.00	230.00	SP Steel	18.59		1
22	Boise Bench	Caldwell	230.00	230.00	S Tower	7.52		1
23	Boise Bench	Caldwell	230.00	230.00	H Wood	33.53		1
24	Boise Bench	Cloverdale	230.00	230.00	S Tower	15.99		2
25	Boardman	Dalreed Sub	230.00	230.00	H Wood	1.68		1
26	Brownlee 714	Oxbow	230.00	230.00	SP Steel	11.13		2
27	Caldwell	Ontario	230.00	230.00	H Wood	27.11		1
28	Caldwell	Ontario	230.00	230.00	S Tower	3.31		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	68.24		1
31	Boise Bench	Midpoint #1	230.00	230.00	S Tower	0.86		1
32	Boise Bench	Midpoint #1	230.00	230.00	H Wood	108.11		1
33	Brownlee	Quartz Jct	230.00	230.00	S Tower	1.52		1
34	Brownlee	Quartz Jct	230.00	230.00	H Wood	41.71		1
35	Brownlee	Boise Bench #1 & #2	230.00	230.00	S Tower	99.99		2
36					TOTAL	4,678.88	11.02	161

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	04/11/2008	End of 2007/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
2X1780 ACSR		446,708	446,708					1
								2
1272 ACSR	256,381	21,776,998	22,033,379					3
1272 ACSR	483,309	15,888,761	16,372,070					4
795 ACSR	571,979	10,996,449	11,568,428					5
1272 ACSR	344,220	6,028,033	6,372,253					6
715.5 ACSR	283,143	5,779,608	6,062,751					7
715.5 ACSR	64,851	7,786,556	7,851,407					8
715.5 ACSR	51,448	347,946	399,394					9
								10
795 ACSR	51,414	2,411,863	2,463,277					11
715.5 ACSR	9,145	998,452	1,007,597					12
1272 ACSR	108,301	2,502,500	2,610,801					13
795 ACSR		6,186	6,186					14
715.5 ACSR	18,829	969,476	988,305					15
1272 ACSR	1,190	51,525	52,715					16
2X954 ACSR	1,676,838	20,266,395	21,943,233					17
715.5 ACSR	347,962	2,012,372	2,360,334					18
715.5 ACSR								19
1272 ACSR	1,899	212,523	214,422					20
1590 ACSR	2,138,236	8,755,911	10,894,147					21
1272 ACSR	1,134,421	5,699,649	6,834,070					22
715.5 ACSR								23
1272 ACSR	3,062,812	6,583,109	9,645,921					24
795 AAC		80,895	80,895					25
954 ACSR	34,174	16,026,470	16,060,644					26
2X954 ACSR	194,763	5,925,083	6,119,846					27
1272 ACSR								28
1272 ACSR	81,701	1,666,354	1,748,055					29
1590 ACSR	618,217	22,439,850	23,058,067					30
715.5 ACSR	336,186	3,776,464	4,112,650					31
715.5 ACSR								32
795 ACSR	53,068	2,011,507	2,064,575					33
795 ACSR								34
VARIOUS	269,431	7,991,043	8,260,474					35
	28,516,168	350,073,050	378,589,218	13,765,083	2,786,071	1,053,886	17,605,040	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	04/11/2008	End of 2007/Q4

TRANSMISSION LINE STATISTICS

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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	Oxbow	Brownlee	230.00	230.00	S Tower	10.23		2
2	Boise Bench	Midpoint #2	230.00	230.00	S Tower	3.42		1
3	Boise Bench	Midpoint #2	230.00	230.00	H Wood	102.53		1
4	Oxbow	Pallette Jct	230.00	230.00	S Tower	20.25		2
5	Pallette Jct	Imnaha	230.00	230.00	H Wood	24.43		2
6	Hells Canyon	Palette Jct	230.00	230.00	S Tower	8.24		2
7	Brownlee	Boise Bench	230.00	230.00	S Tower	102.30		2
8	Boise Bench	Midpoint #3	230.00	230.00	H Wood	106.34		1
9	Palette Jct	Enterprise	230.00	230.00	H Wood	29.08		1
10	Borah	Brady #2	230.00	230.00	S Tower	0.43		1
11	Borah	Brady #2	230.00	230.00	H Wood	3.58		1
12	Borah	Brady #1	230.00	230.00	H Wood	3.98		1
13								
14	Goshen	State Line	161.00	161.00	H Wood	90.50		1
15	Don	Goshen	161.00	161.00	S Tower	2.39		2
16	Don	Goshen	161.00	161.00	H Wood	48.43		2
17								
18	American Falls Power Plant	Adelaide	138.00	138.00	H Wood	9.84		2
19	American Falls Power Plant	Adelaide	138.00	138.00	S P Wood	2.58		2
20	Minidoka Loop	Adelaide	138.00	138.00	S Tower	1.11		2
21	Nampa	Caldwell	138.00	138.00	S P Wood	10.73		2
22	Upper Salmon	Mountain Home Jct		138.00	H Wood	53.40		1
23	Upper Salmon	Cliff	138.00	138.00	H Wood	30.80		1
24	Eastgate	Russet	138.00	138.00	S P Wood	2.30		1
25	Brady	Fremont	138.00	138.00	S Tower	1.00		2
26	Brady	Fremont	138.00	138.00	H Wood	24.32		2
27	Brady	Fremont	138.00	138.00	S P Wood	24.35		2
28	King	Lower Malad	138.00	138.00	H Wood	84.91		2
29	Emmett Jct	Payette	138.00	138.00	H Wood	66.20		2
30	Mountain Home AFB Tap		138.00	138.00	H Wood	6.21		1
31	Ontario	Quartz	138.00	138.00	H Wood	73.41		1
32	King	American Falls PP	138.00	138.00	S Tower	1.03		2
33	King	American Falls PP	138.00	138.00	H Wood	146.40		1
34	King	American Falls PP	138.00	138.00	S P Wood	3.71		1
35	Duffin	Clawson	138.00	138.00	H Wood	6.22		1
36					TOTAL	4,678.88	11.02	161

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) 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	14,810	1,182,550	1,197,360					1
715.5 ACSR	227,825	5,764,129	5,991,954					2
VARIOUS								3
1272 ACSR	23,308	2,075,244	2,098,552					4
1272 ACSR	138,477	1,263,618	1,402,095					5
1272 ACSR	10,737	1,252,130	1,262,867					6
954 ACSR	170,694	5,620,492	5,791,186					7
715.5 ACSR	247,857	4,954,729	5,202,586					8
1272 ACSR	51,122	1,631,895	1,683,017					9
1272 ACSR	3,068	226,250	229,318					10
715.5 ACSR								11
1272 ACSR	10,064	339,595	349,659					12
								13
250 COPPER	16,155	648,382	664,537					14
715.5 ACSR	76,041	1,652,914	1,728,955					15
397.5 ACSR								16
								17
250 COPPER	26,507	2,388,737	2,415,244					18
250 COPPER								19
715.5 ACSR	15,088	249,232	264,320					20
795 AAC	157,432	1,954,139	2,111,571					21
795 ACSR	47,687	1,858,259	1,905,946					22
795 ACSR	43,568	764,183	807,751					23
795 AAC	270,823	557,504	828,327					24
VARIOUS	564,932	3,557,039	4,121,971					25
VARIOUS								26
VARIOUS								27
VARIOUS	76,823	1,622,351	1,699,174					28
VARIOUS	30,918	2,291,614	2,322,532					29
397.5 ACSR	1,955		1,955					30
VARIOUS	34,428	1,552,878	1,587,306					31
715.5 ACSR	148,914	5,544,203	5,693,117					32
715.5 ACSR								33
715.5 ACSR								34
4\0	4,191	309,827	314,018					35
	28,516,168	350,073,050	378,589,218	13,765,083	2,786,071	1,053,886	17,605,040	36

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION 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	American Falls	Brady Tie	138.00	138.00	H Wood	0.33		1
2	Upper Salmon A-B	King	138.00	138.00	H Wood	5.88		1
3	Upper Salmon B	Wells	138.00	138.00	H Wood	125.61		1
4	King	Wood River	138.00	138.00	H Wood	73.57		1
5	Boise Bench	Grove	138.00	138.00	S P Wood	10.47		2
6	Quartz	John Day	138.00	138.00	H Wood	67.31		1
7	Sinker Creek Tap		138.00	138.00	H Wood	2.83		1
8	Mora	Cloverdale	138.00	138.00	H Wood	2.57		1
9	Mora	Cloverdale	138.00	138.00	S P Wood	22.37		1
10	Stoddard Jct	Stoddard Sub	138.00	138.00	S P Steel	3.80		1
11	Fossil Gulch Tap		138.00	138.00	H Wood	1.95		1
12	Wood River	Midpoint	138.00	138.00	H Wood	53.06		2
13	Wood River	Midpoint	138.00	138.00	S P Wood	16.74		2
14	Oxbow	McCall	138.00	138.00	H Wood	38.47		1
15	Oxbow	McCall	138.00	138.00	S P Wood	2.50		1
16	Lowell Jct	Nampa	138.00	138.00	S P Wood	7.59		2
17	Hunt	Milner	138.00	138.00	S P Wood	19.40		1
18	Strike	Bruneau Bridge	138.00	138.00	H Wood	13.47		1
19	American Falls	Kramer Sub	138.00	138.00	S P Wood	18.41		2
20	Pingree	Haven	138.00	138.00	S P Wood	11.75		1
21	Midpoint	Twin Falls	138.00	138.00	S P Wood	25.13		2
22	Twin Falls	Russett	138.00	138.00	S P Wood	1.72		1
23	Blackfoot	Aiken	138.00	138.00	S P Wood	6.17		2
24	Peterson	Tendoy	138.00	138.00	H Wood	57.26		1
25	Eastgate Tap	Eastgate	138.00	138.00	S P Wood	7.32		1
26	Boise Bench	Mora	138.00	138.00	H Wood	13.14		2
27	Bowmont-Caldwell	Simplot Sub	138.00	138.00	S P Wood	0.51		1
28	Gary Lane	Eagle	138.00	138.00	S P Wood	6.44		1
29	Locust Grove	Blackcat Sub	138.00	138.00	S P Steel	9.92	2.98	1
30	Boise Bench	Butler	138.00	138.00	S P Wood	0.08	4.02	1
31	Eagle	Star		138.00	S P Wood	6.35		1
32	Karcher Sub	Zilog Tap	138.00	138.00	S P Steel	2.09		1
33	Cloverdale - 712	712 - Wye	138.00	138.00	S P Steel	0.24	4.02	1
34	Butler	Wye	138.00	138.00	S P Steel	2.86		1
35	Horseflat	Starkey	138.00	138.00	S P Steel	34.56		1
36					TOTAL	4,678.88	11.02	161

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	04/11/2008	End of 2007/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
954 ACSR		96,921	96,921					1
250 COPPER	2,741	93,073	95,814					2
VARIOUS	28,490	1,745,804	1,774,294					3
VARIOUS	173,683	2,355,148	2,528,831					4
VARIOUS	225,602	1,630,589	1,856,191					5
397.5 ACSR	92,173	2,362,416	2,454,589					6
VARIOUS	20	77,199	77,219					7
715.5 ACSR	2,225,226	6,996,618	9,221,844					8
VARIOUS								9
1272 ACSR								10
250 COPPER	450	63,439	63,889					11
397.5 ACSR	281,064	6,374,306	6,655,370					12
397.5 ACSR								13
397.5 ACSR	109,899	2,314,194	2,424,093					14
397.5 ACSR								15
715.5 ACSR	211,131	1,493,264	1,704,395					16
715.5 ACSR	3,324	1,187,302	1,190,626					17
397.5 ACSR	14,927	587,404	602,331					18
715.5 ACSR	13,734	1,052,549	1,066,283					19
397.5 ACSR	11,213	778,092	789,305					20
VARIOUS	54,848	2,958,765	3,013,613					21
715.5 ACSR	16,790	206,158	222,948					22
715.5 ACSR	13,616	456,919	470,535					23
397.5 ACSR	395,696	3,449,949	3,845,645					24
715.5 ACSR	45,989	1,058,898	1,104,887					25
715.5 ACSR	14,697	627,703	642,400					26
795 AAC		49,642	49,642					27
795 AAC	489,037	1,944,888	2,433,925					28
1272 ACSR	935,725	3,610,071	4,545,796					29
1272 ACSR	34,687	838,605	873,292					30
715.5 ACSR		2,909,433	2,909,433					31
795 AAC	43,035	443,805	486,840					32
1272 ACSR	140,412	709,148	849,560					33
795 ACSR	134,471	1,405,436	1,539,907					34
954 ACSR	648,186	13,145,197	13,793,383					35
	28,516,168	350,073,050	378,589,218	13,765,083	2,786,071	1,053,886	17,605,040	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	04/11/2008	End of 2007/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION 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	Chestnut	Happy Valley	138.00	138.00	S P Steel	2.78		1
2	McCall	Lake Fork	138.00	138.00	S P Wood	8.70		1
3			138.00	138.00	S Steel	2.90		
4	Caldwell	Willis	138.00	138.00	S P Steel	1.30		1
5	Caldwell	Willis	138.00	138.00	S P Steel	1.59		1
6	Caldwell	Willis	138.00	138.00	S P Wood	0.82		1
7	Valivue Tap		138.00	138.00	S P Steel	0.82		2
8	Kinport	Don #1	138.00	138.00	S Tower	1.24		2
9	Twin Falls PP Tap		138.00	138.00	H Wood	0.82		1
10	American Falls PP	Amercian Falls Trans ST	138.00	138.00	S P Steel	0.38		1
11	Lower Salmon	King Tie	138.00	138.00	H Wood	0.22		1
12	C J Strike	Strike Jct	138.00	138.00	S Tower	4.31		2
13	Strike Jct	Mountain Home Jct	138.00	138.00	H Wood	26.69		1
14	Strike Jct	Bowmont		138.00	H Wood	0.05		1
15	Strike Jct	Bowmont	138.00	138.00	S Tower	0.36		1
16	Strike Jct	Bowmont	138.00	138.00	H Wood	68.14		1
17	Lucky Peak	Lucky Peak Jct	138.00	138.00	H Wood	4.43		2
18	Bliss	King	138.00	138.00	H Wood	10.44		1
19	Milner Deadend	Milner PP	138.00	138.00	S P Wood	1.31		1
20	Swan Falls Tap		138.00	138.00	H Wood	0.95		1
21								
22								
23								
24	Hines	BPA (Harney)	115.00	115.00	H Wood	3.28		1
25								
26								
27	69 Kv Lines		69.00	69.00	H Wood	166.31		1
28	69 Kv Lines		69.00	69.00	S P Wood	943.39		1
29								
30								
31	46 Kv Lines		46.00	46.00	S P Wood	412.25		1
32								
33								
34								
35								
36					TOTAL	4,678.88	11.02	161

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1272 ACSR	78,579	1,821,921	1,900,500					1
715.5 ACSR	399,781	4,731,449	5,131,230					2
								3
1272 ACSR	168,225	2,141,218	2,309,443					4
795 ACSR								5
795 ACSR								6
795 ACSR		351,497	351,497					7
715.5 ACSR	1,174	212,777	213,951					8
250 COPPER	58	53,889	53,947					9
715.5 ACSR		76,560	76,560					10
397.5 ACSR		4,406	4,406					11
715.5 ACSR	1,074	253,872	254,946					12
397.5 ACSR	4,355	524,571	528,926					13
715.5 ACSR	29,902	1,776,898	1,806,800					14
715.5 ACSR								15
								16
715.5 ACSR	7	279,481	279,488					17
715.5 ACSR	5,620	964,435	970,055					18
715.5 ACSR	2,814	183,606	186,420					19
397.5 ACSR	12,885	261,511	274,396					20
								21
								22
								23
397.5 ACSR	1,978	63,404	65,382					24
								25
								26
VARIOUS	928,990	36,062,702	36,991,692					27
VARIOUS								28
								29
								30
VARIOUS	176,265	8,585,338	8,761,603					31
								32
	5,736,253		5,736,253					33
								34
				13,765,083	2,786,071	1,053,886	17,605,040	35
	28,516,168	350,073,050	378,589,218	13,765,083	2,786,071	1,053,886	17,605,040	36

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	Borah	Hunt	68.24	H Steel	6.50	1	1
2							
3	McCall	Lake Fork	8.70	S P Wood	18.28	1	1
4			2.90	S P Steel	18.28	1	1
5							
6							
7							
8							
9							
10							
11							
12							
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41							
42							
43							
44	TOTAL		79.84		43.06	3	3

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	04/11/2008	End of 2007/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

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

CONDUCTORS			Voltage KV (Operating)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)	(k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
1590	ACSR	Hor 22'	230	618,217	15,814,751	6,625,099		23,058,067	1
									2
715.5	ACSR	TVS 7'	138	399,781	2,361,947	2,369,502		5,131,230	3
715.5	ACSR	TVS 6'	138						4
									5
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									43
				1,017,998	18,176,698	8,994,601		28,189,297	44

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Adelaide	transmission	345.00	138.00	13.80
2	Aiken	distribution	46.00	13.00	
3	Alameda	distribution	46.00	13.00	
4	Alameda	distribution	138.00	13.00	
5	American Falls PP - attended	transmission	138.00	13.80	
6	American Falls	transmission	138.00	46.00	12.50
7	Artesian	distribution	46.00	13.00	
8	Bannock Creek	distribution	46.00	13.00	
9	Bennett Mountain Power Plant	transmission	230.00	18.00	
10	Bennett Mountain Power Plant	transmission	18.00	4.16	
11	Bethel Court	distribution	138.00	13.00	
12	Black Cat	distribution	138.00	13.09	
13	Blackfoot	distribution	46.00	12.50	
14	Blackfoot	distribution	161.00	46.00	12.47
15	Bliss - attended	transmission	138.00	13.80	
16	Blue Gulch	distribution	138.00	34.50	
17	Boise Bench - attended	distribution	138.00	34.50	
18	Boise Bench - attended	transmission	138.00	69.00	13.80
19	Boise Bench - attended	transmission	230.00	138.00	13.80
20	Boise	distribution	138.00	13.00	
21	Borah	transmission	345.00	230.00	13.80
22	Bowmont	distribution	69.00	46.00	6.90
23	Bowmont	distribution	138.00	34.50	
24	Bowmont	distribution	138.00	69.00	13.80
25	Brady	transmission	46.00	12.50	
26	Brady	transmission	230.00	138.00	13.80
27	Brownlee - attended	transmission	230.00	13.80	
28	Bruneau Bridge	distribution	138.00	34.50	
29	Buckhorn	distribution	69.00	35.00	
30	Bucyrus	distribution	46.00	7.20	
31	Buhl	distribution	46.00	13.00	
32	Burley Rural	distribution	69.00	13.00	
33	Butler	distribution	138.00	13.00	
34	Caldwell	distribution	138.00	13.00	
35	Caldwell	distribution	138.00	69.00	13.00
36	Caldwell	transmission	230.00	138.00	12.50
37	Canyon Creek	distribution	138.00	34.50	
38	Canyon Creek	distribution	138.00	69.00	12.50
39	Cascade Power Plant - attended	transmission	69.00	4.60	
40	Cascade	Distribution	69.00	13.10	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
300	2					1
20	2					2
15	1					3
18	1					4
72	1					5
25	1					6
10	1					7
10	1					8
135	1					9
5	1					10
15	1					11
24	1					12
30	2					13
130	4	1				14
69	3					15
15	1					16
42	2					17
75	3					18
494	4					19
67	3					20
450	3	1				21
8	3					22
18	1					23
50	2					24
		6				25
300	3					26
734	5	1				27
30	2					28
20	1					29
6	1	4				30
20	2					31
12	1					32
48	2					33
39	2	1				34
50	2	1				35
240	2					36
15	1					37
		1				38
12	1					39
10	1					40

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Chestnut	distribution	138.00	13.00	
2	Clear Lake - attended	transmission	46.00	2.30	
3	Cliff	transmission	138.00	46.00	12.50
4	Cloverdale	transmission	138.00	13.00	
5	Dale	distribution	69.00	13.00	
6	Dale	distribution	138.00	34.50	
7	Dale	distribution	138.00	46.00	12.50
8	Danskin	transmission	138.00	12.00	
9	Don	distribution	138.00	7.60	
10	Don	distribution	138.00	13.20	
11	Don	distribution	138.00	13.00	
12	DRAM	distribution	138.00	13.00	
13	DRAM	distribution	230.00	138.00	13.80
14	Duffin	distribution	138.00	34.50	
15	Eagle	distribution	138.00	13.00	
16	Eastgate	distribution	138.00	13.00	
17	Eckert	distribution	138.00	36.20	
18	Eden	distribution	138.00	34.50	
19	Eden	distribution	138.00	46.00	12.50
20	Elkhorn	distribution	138.00	12.00	
21	Elmore	transmission	138.00	34.50	
22	Elmore	distribution	138.00	69.00	12.50
23	Emmett	distribution	138.00	12.50	
24	Emmett	distribution	138.00	69.00	12.50
25	Falls	distribution	46.00	12.50	
26	Filer	distribution	46.00	12.50	
27	Flying H	distribution	69.00	2.40	
28	Fort Hall	distribution	46.00	12.50	
29	Fossil Gulch	distribution	138.00	2.40	4.60
30	Fossil Gulch	distribution	138.00	34.50	
31	Fremont	transmission	138.00	46.00	12.50
32	Gary	distribution	138.00	13.00	
33	Gem	distribution	69.00	13.00	
34	Golden Valley	distribution	69.00	12.50	
35	Gowen Substation	distribution	138.00	35.00	
36	Grindstone	distribution	35.00	12.50	
37	Grove	distribution	138.00	12.50	
38	Hagerman	distribution	46.00	12.50	
39	Hailey	distribution	138.00	12.50	
40	Happey Valley	distribution	138.00	13.09	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Number of Units (j)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Total Capacity (In MVa) (k)	Line No.
48	2					1
4	1					2
16	3	1				3
48	2					4
		10				5
27	1					6
25	1					7
96	2					8
18	1					9
164	10	5				10
26	1	1				11
134	8					12
160	2					13
36	2					14
38	2					15
36	2					16
18	1					17
24	1					18
15	1					19
15	2					20
17	1					21
30	2					22
15	1					23
25	1					24
17	2					25
10	1					26
15	2					27
10	1	1				28
8	1					29
15	1					30
50	3	1				31
36	2					32
17	2					33
10	1	1				34
24	1					35
10	2					36
72	3					37
12	2					38
20	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) 04/11/2008	Year/Period of Report End of 2007/Q4

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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	Haven	distribution	46.00	34.50	
2	Hewlett Packard	distribution	138.00	13.10	
3	Hidden Springs	distribution	138.00	13.09	
4	Highland	distribution	138.00	13.09	
5	Hill	distribution	138.00	12.50	
6	Homedale	distribution	69.00	12.50	
7	Horse Flat	transmission	230.00	138.00	13.80
8	Horseshoe Bend	distribution	35.00	12.50	
9	Horseshoe Bend	distribution	69.00	36.20	
10	Horseshoe Bend	distribution	69.00	25.00	
11	Huston	distribution	69.00	13.00	
12	Hulen	distribution	46.00	13.00	
13	Hunt	transmission	230.00	138.00	13.80
14	Hydra	distribution	138.00	34.50	
15	Island	distribution	69.00	12.50	
16	Jerome	distribution	138.00	12.50	
17	Julion Clawson	distribution	138.00	34.50	
18	Joplin	distribution	138.00	13.00	
19	Joplin	distribution	138.00	35.00	18.00
20	Karcher	distribution	138.00	13.09	
21	Kenyon	distribution	69.00	12.50	
22	Ketchum	distribution	138.00	12.50	
23	Kinport	transmission	161.00	46.00	13.00
24	Kinport	transmission	230.00	138.00	12.50
25	Kinport	transmission	230.00	138.00	13.80
26	Kinport	transmission	345.00	230.00	13.80
27	Kramer	distribution	138.00	34.50	
28	Kramer	distribution	138.00	13.00	
29	Kuna	distribution	138.00	13.00	
30	Lake Fork	distribution	138.00	36.20	
31	Lake Fork	transmission	138.00	69.00	12.50
32	Lamb	distribution	138.00	13.09	
33	Lansing	distribution	69.00	13.00	
34	Lincoln	distribution	138.00	13.00	
35	Linden	distribution	138.00	13.00	
36	Locust	distribution	138.00	34.50	
37	Locust	transmission	230.00	138.00	13.00
38	Lower Malad - attended	transmission	138.00	7.20	
39	Lower Salmon - attended	transmission	138.00	13.80	
40	Map Rock	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) 04/11/2008	Year/Period of Report End of 2007/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
12	1					1
20	1					2
8	1					3
18	1					4
24	1					5
20	2					6
100	1					7
5	1					8
12	1					9
5	1					10
10	1					11
8	1	1				12
300	3					13
24	1					14
12	1					15
20	1					16
30	2					17
15	1					18
1						19
12	1					20
20	2					21
42	2					22
		7				23
180	1					24
180	1					25
600	3	1				26
12	1					27
18	1					28
15	1					29
18	1					30
15	1					31
18	1					32
12	1					33
11	1					34
33	2					35
48	2					36
360	2					37
15	1					38
70	4					39
10	1					40

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	McCall	distribution	69.00	12.50	
2	McCall	distribution	138.00	35.00	
3	McCall	distribution	138.00	69.00	12.50
4	Meridian	distribution	138.00	13.00	
5	Micron	distribution	138.00	12.50	
6	Midpoint	transmission	230.00	138.00	13.80
7	Midpoint	transmission	345.00	230.00	13.80
8	Midpoint	transmission	500.00	345.00	
9	Midrose	distribution	138.00	13.09	
10	Milner	distribution	138.00	69.00	13.80
11	Milner	distribution	69.00	46.00	7.20
12	Milner	distribution	138.00	34.50	
13	Milner PP - attended	transmission	138.00	13.80	
14	Moonstone	distribution	138.00	34.50	
15	Mora	distribution	138.00	34.50	
16	Moreland	distribution	46.00	12.50	
17	Moreland	distribution	46.00	34.50	12.50
18	Mountain Home	distribution	69.00	12.50	
19	Mountain Home Air Force Base	distribution	69.00	12.50	
20	Mountain Home Air Force Base	distribution	138.00	12.50	
21	Nampa	distribution	230.00	138.00	13.80
22	Nampa	distribution	138.00	12.50	
23	New Meadows	distribution	69.00	35.00	
24	New Plymouth	distribution	69.00	12.50	
25	Notch Butte	distribution	13.00	7.56	
26	Parma	distribution	69.00	12.50	
27	Parma	distribution	69.00	34.50	
28	Paul	distribution	138.00	34.50	12.50
29	Payette	distribution	138.00	12.50	
30	Pingree	distribution	138.00	46.00	12.50
31	Pingree	distribution	138.00	36.00	
32	Pleasant Valley	distribution	138.00	34.50	
33	Pocatello	distribution	46.00	12.50	
34	Portneuf	distribution	138.00	36.20	
35	Portneuf	distribution	46.00	35.00	
36	Rockford	distribution	46.00	12.50	
37	Russett	distribution	138.00	12.50	
38	Sailor Creek	distribution	138.00	2.40	
39	Sailor Creek	distribution	138.00	34.50	
40	Salmon	distribution	69.00	12.50	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2008	End of 2007/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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.
8	1					1
18	1					2
30	1					3
36	2					4
48	4					5
120	1					6
720	2					7
750	3	1				8
18	1					9
75	3	1				10
8	3	1				11
16	1					12
36	1					13
12	1					14
39	2					15
13	2					16
10	3	1				17
15	1					18
		1				19
18	1					20
180	1					21
50	3					22
8	3	1				23
10	1					24
11	1					25
10	1					26
12	1					27
36	2	1				28
22	3					29
50	3					30
22	2					31
42	2					32
36	2					33
18	1					34
		1				35
14	2					36
18	1					37
15	2					38
15	1					39
10	1	4				40

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

SUBSTATIONS

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

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Salmon	distribution	69.00	34.50	12.50
2	Shoshone	distribution	46.00	13.00	
3	Shoshone	distribution	46.00	7.20	
4	Shoshone Falls - attended	transmission	46.00	2.30	
5	Shoshone Falls - attended	transmission	46.00	6.60	
6	Silver	distribution	138.00	34.50	
7	Simplot	distribution	138.00	12.50	
8	Sinker Creek	distribution	138.00	34.50	
9	Siphon	distribution	138.00	34.50	
10	South Park	distribution	46.00	13.00	
11	Star	distribution	138.00	13.00	
12	Starkey	Transmission	138.00	69.00	12.50
13	State	distribution	69.00	12.50	
14	Stoddard	distribution	138.00	13.00	
15	Strike Power Plant - attended	transmission	138.00	13.80	
16	Sugar	distribution	138.00	34.50	
17	Swan Falls - attended	transmission	138.00	6.90	
18	Taber	distribution	46.00	12.50	
19	Ten Mile	distribution	138.00	13.09	
20	Terry	distribution	138.00	12.50	
21	Thousand Springs - attended	transmission	46.00	6.90	
22	Thousand Springs - attended	transmission	7.00	2.40	
23	Toponis	distribution	138.00	34.50	
24	Twin Falls	distribution	138.00	13.00	
25	Twin Falls	distribution	138.00	46.00	12.50
26	Twin Falls PP - attended	transmission	138.00	7.20	
27	Twin Falls PP - attended	transmission	138.00	13.20	
28	Upper Malad - attended	transmission	46.00	7.20	
29	Upper Salmon- attended	transmission	138.00	7.20	
30	Ustick	distribution	138.00	12.50	
31	Vallivue	distribution	138.00	13.09	
32	Victory	distribution	138.00	12.50	
33	Ware	distribution	69.00	12.50	
34	Weiser	distribution	69.00	12.50	
35	Weiser	distribution	138.00	69.00	12.50
36	Wilder	distribution	69.00	13.00	
37	Willis	distribution	138.00	13.09	
38	Wye	distribution	138.00	13.00	
39	Zilog	distribution	138.00	13.09	
40					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
10	3	1				1
10	1	1				2
2	3					3
3	1					4
10	1					5
12	1					6
15	1					7
12	1					8
33	2					9
10	1					10
18	1					11
18	1					12
33	2					13
15	1					14
83	3					15
20	2					16
18	1					17
5	1					18
24	1					19
42	3					20
8	1					21
2	1					22
18	1					23
40	2					24
33	2					25
9	1					26
72	1					27
8	1					28
36	4					29
44	2					30
18	1					31
24	1					32
12	1					33
20	2					34
25	1					35
10	1					36
18	1					37
56	3					38
24	1					39
						40

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1					
2	The above are all State of Idaho				
3					
4	Montana:				
5	Peterson	transmission	230.00	69.00	13.20
6					
7	Nevada:				
8	Valmy - attended	transmission	345.00	21.30	
9	Wells	transmission	138.00	69.00	12.50
10					
11	Oregon:				
12	Boardman - attended	transmission	500.00	24.00	
13	Cairo	distribution	69.00	12.50	
14	Hells Canyon - attended	transmission	230.00	13.80	
15	Hines	transmission	138.00	115.00	12.50
16	Malheur Butte	distribution	69.00	34.50	12.50
17	Nyssa	distribution	69.00	12.50	
18	Ontario	distribution	138.00	12.50	
19	Ontario	distribution	138.00	69.00	12.50
20	Ontario	distribution	230.00	138.00	13.80
21	Ore-Ida	distribution	69.00	12.50	
22	Oxbow - attended	transmission	138.00	69.00	13.00
23	Oxbow - attended	transmission	230.00	13.80	
24	Oxbow - attended	transmission	230.00	138.00	13.80
25	Quartz	transmission	138.00	69.00	12.50
26	Quartz	transmission	230.00	138.00	13.00
27	Vale	distribution	69.00	13.09	
28					
29	Wyoming:				
30	Jim Bridger - attended	transmission	345.00	22.00	
31					
32					
33					
34					
35					
36					
37	Transformers-distribution substations under 10,000				
38	KVA 89 unattended.				
39					
40					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/11/2008	Year/Period of Report End of 2007/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
						2
						3
						4
20	2	2				5
						6
						7
150	1					8
20	3	1				9
						10
						11
55	1					12
12	1					13
501	4					14
40	1					15
10	3					16
20	2					17
38	2					18
75	3	1				19
240	2					20
15	1					21
10	3	1				22
244	2					23
100	1					24
30	2					25
100	3	1				26
10	1					27
						28
						29
748	1					30
						31
						32
						33
						34
						35
						36
						37
351						38
						39
						40

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MULTI-STATE ELECTRIC COMPANIES

INDEX

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	$ 841,478,350	$ 876,469,532
3	Operating Expenses			
4	Operation Expenses (401)	15	517,569,128	532,371,073
5	Maintenance Expenses (402)	15	63,803,165	60,277,132
6	Depreciation Expense (403)		88,365,074	84,214,083
7	Amort. & Depl. of Utility Plant (404-405)		4,925,898	587,822
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)		2,114,441	10,391,374
13	Taxes Other Than Income Taxes (408.1)	2	15,922,687	16,840,362
14	Income Taxes - Federal (409.1)	2	2,592,539	51,553,061
15	- Other (409.1)	2	(6,483,885)	5,093,547
16	Provision for Deferred Income Taxes (410.1 & 411.1) Net	2	34,515,479	(8,706,428)
17	Investment Tax Credit Adj. - Net (411.4)	2	1,862,104	320,531
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)		725,186,631	752,942,558
24				
25	Net Utility Operating Income (Enter Total of line 2 less 23)			
26	(Carry forward to page 11, line 27)		$ 116,291,719	$ 123,526,975

TAXES ALLOCATED TO IDAHO

Kind of Tax	Taxes Charged During Year
Taxes Other Than Income Taxes:	
Labor Related:	
FICA	$ 10,320,049
FUTA	118,363
State Unemployment	232,705
Payroll Deduction & Loading	(10,671,116)
Total Labor Related	(0)
Property Taxes	12,895,150
Kilowatt-hour Tax	1,210,073
Licenses	3,010
Regulatory Commission Fees	1,599,171
Irrigation PIC	215,283
Total Taxes Other Than Income Taxes	15,922,687
Federal Income Taxes	2,592,539
State Income Taxes	(6,483,885)
Deferred Income Taxes	34,515,479
Investment Tax Credit Adjustment - Net	1,862,104
Total Taxes Allocated to Idaho	$ 48,408,925

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)	$ 6,717,530	$ 5,975,468
2	Customer Accounts Receivable (Account 142)	54,218,159	$ 62,122,209
3	Other Accounts Receivable (Account 143)	10,081,728	$ 7,080,171
4	(Disclose any capital stock subscription received)		
5	Total	$ 71,017,417	$ 75,177,848
6			
7	Less: Accumulated Provision for Uncollectible		
8	Accounts-Cr. (Account 144)	968,073	1,305,058
9			
10	Total, Less Accumulated Provision for		
11	Uncollectible Accounts	$ 70,049,344	$ 73,872,789
12			
13			
14	Notes Receivable - Account 141: (at 12-31-07)		
15	Directors, officers, and employees - $ 4,453,176		
16			
17			
18	Other Accounts Receivable - Account 143: (at 12-31-07)		
19	Directors, officers, and employees - $ 4,311		
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	$ 868,749	$	$	$ 294,883	1,163,632
23	Prov. for uncollectibles					
24	for year	99,324			42,103	141,427
25	Accounts written off					
26	Coll. of accounts					
27	written off					
28	Adjustments (explain)					
29						
30						
31						
32	Balance end of year	$ 968,073	$ -	$ -	$ 336,985	$ 1,305,058
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	$ 9,154,480	$ 44,578,462	$ 32,205,316	$ 21,527,626	
4						
5						
6						
7						
8						
9						
10	Total Account 145	9,154,480	44,578,462	32,205,316	21,527,626	
11						
12	Account 146:					
13						
14						
15						
16	IDACORP, Inc	$ -	$ 58,114,469	$ 58,114,469	$ -	
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31	Total Account 146	$ -	$ 58,114,469	$ 58,114,469	$ -	
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	CJ Strike Power Plant- Disposal of	$ 62,967	10/24/2007	$ 48,872	
5	excess land				
6					
7	CJ Strike Power Plant- Disposal of	105,000	11/15/2007	72,339	
8	excess land				
9					
10	Misc Items (4)	36,663		200,153	
11					
12					
13					
14	Total gain..	$ 204,630		$ 321,364	
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31	Total loss..	$ 0			$ 0

STATE OF IDAHO - TOTAL SYSTEM DATA

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

Line No.	PAYEE (a)	SERVICE TYPE (b)	Amount (c)
1	ADECCO	Mapping Services	$ 38,095
2	ADP	Accounting Services	51,170
3	ADVANCED SYSTEMS GROUP	Computer Support Services	14,063
4	AERO-GRAPHICS	Mapping Services	15,506
5	AMEC EARTH & ENVIRONMENTAL, IN	Environmental Services	14,146
6	ASCENTIUM CORPORATION	PM Consultant	15,863
7	ATER, WYNNE LLP	Legal Services	36,858
8	BARKER, ROSHOLT & SIMPSON LLP	Legal Services	317,271
9	BIDART & ROSS INC	Management Services	70,722
10	BLACKBURN & JONES LLP	Legal Services	147,939
11	BLUE HERON CONSULTING, INC	Legal Services	297,000
12	BOUILLON INTEGRATED SYSTEMS, I	Computer Support Services	23,950
13	BRENNEMAN, JOHN	Lobby Services	73,907
14	BRIGHAM YOUNG UNIVERSITY	Environmental Services	50,500
15	BROWN RUDNICK BERLACK ISRAELS	Lobby Services	54,000
16	BROWNSTEIN HYATT & FARBER, P C	Legal Services	1,338,228
17	CASCADE ENERGY ENGINEERING INC	Engineering Services	76,360
18	CERTUS SOFTWARE INC	Consulting Services	24,069
19	CHRISTENSEN REALTY INVESTMENT,	Parking Services	11,880
20	CHURCH, JOHN S	Economic Services	72,000
21	COMSYS INFORMATION TECHNOLOGY	Computer Support Services	176,949
22	CORNERSTONE SYSTEMS INC	Computer Support Services	548,871
23	CRI ADVANTAGE	Computer Support Services	130,915
24	CTA ARCHITECTS	Architect Services	66,210
25	CUMMINS & BARNARD, INC.	Environmental Services	58,539
26	DAVID EVANS AND ASSOCIATES	Management Services	92,327
27	DAVIS WRIGHT TREMAINE LLP	Legal Services	785,720
28	DEAN & CARTER PLLC	Legal Services	11,439
29	DELOITTE & TOUCHE	Accounting Services	717,738
30	DELOITTE & TOUCHE LLP	Accounting Services	99,186
31	DEUTSCHE BANK TRUST CO	Accounting Services	15,297
32	DEVELOPMENT DIMNENSIONS	Management Services	10,910
33	DEWEY & LEBOEUF	Legal Services	708,845
34	DHI INC	Environmental Services	91,513
35	ECOANALYSTS INC	Environmental Services	188,829
36	ECOS CONSULTING	Consulting Services	133,665
37	EMC CORPORATION	Computer Support Services	11,258
38	ENERNEX CORPORATION	Consulting Services	37,553
39	ERNST & YOUNG LLP	Accounting Services	158,665
40	EVERGREEN CONSULTING GROUP, LL	Consulting Services	22,845
41	FINANCIAL CONCEPTS AND APPLICA	Accounting Services	12,225
42	GJORDING & FOUSER, PLLC	Management Services	22,440
43	GLAHE & ASSOCIATES INC	Environmental Services	27,540
44	GLOBAL INSIGHT	Environmental Services	25,662
45	H CHARLES DURICK	Consulting Services	21,575

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	HALL FARLEY OBERRECHT & B	Legal Services	$ 42,439
47	HARDESTY, REBECCA	Environmental Services	58,929
48	HDR ENGINEERING, INC	Engineering Services	20,453
49	HOPKINS RODEN CROCKETT HANSEN	Lobby Services	72,175
50	HR MANAGEMENT SOLUTIONS LLC	Management Services	13,500
51	HUNTLEY PARK LLP	Legal Services	80,000
52	IBM	Computer Support Services	523,021
53	IDAHO STATE UNIVERSITY	Environmental Services	17,759
54	INNOVATIVE CLAIM SOLUTIONS	Management Services	30,025
55	INTERMOUNTAIN TECHNOLOGY GROUP	Computer Support Services	108,807
56	J R SIMPLOT COMPANY	Management Services	20,000
57	JUB ENGINEERS	Engineering Services	86,495
58	L CONWAY CONSULTING, INC	Consulting Services	27,817
59	LAMB WESTON	Management Services	10,000
60	LE BOEUF LAMB GREENE	Legal Services	2,157,252
61	LIGHTING DESIGN LAB	Management Services	10,000
62	MALANDRO COMMUNICATION INC	Consulting Services	566,851
63	MAPFRAME CORPORATION	Computer Support Services	103,800
64	MARSH ADVANTAGE AMERICA	Management Services	12,000
65	MATERIALS TESTING & INSPE	Management Services	19,409
66	MCDOWELL & RACKNER PC	Legal Services	127,631
67	MICON INC	Computer Support Services	42,422
68	MICROSOFT CORP	Computer Support Services	283,321
69	MILLER BATEMAN LLP	Legal Services	167,544
70	MWH AMERICAS, INC.	Management Services	96,860
71	NEXTAXIOM TECHNOLOGY INC	Consulting Services	20,687
72	NEXUS ENERGY SOFTWARE	Management Services	45,400
73	NIELSEN GROUP INC, THE	Consulting Services	144,645
74	NORTHWEST POWER AND CONSERVATI	Environmental Services	43,000
75	ORACLE CORPORATION	Computer Support Services	71,305
76	PACIFIC INTERNATIONAL ENGINEER	Engineering Services	50,175
77	PAINE, HAMBLEN, COFFIN , BROOK	Management Services	32,967
78	PARR WADDOUPS BROWN GEE AND LO	Environmental Services	113,105
79	PARSONS BRINCKERHOFF QUADE	Management Services	17,176
80	PEARSON'S WRITING, EDITING, &	Management Services	70,552
81	PINK ELEPHANT CORP	Computer Support Services	24,843
82	PLANNEDSCAPE	Consulting Services	60,858
83	PORTLAND ENERGY CONSERVATION,	Environmental Services	200,349
84	POWER ENGINEERS INC	Engineering Services	14,768
85	QUANTEC LLC	Consulting Services	21,845
86	RESOURCE DATA, INC	Computer Support Services	10,815
87	RIDDELL WILLIAMS P.S.	Legal Services	108,639
88	RIGHT SYSTEMS, INC	Management Services	30,240
89	RIPLEY, LARRY D	Legal Services	22,150

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	RIVERSIDE TECHNOLOGY INC	Management Services	551,254
91	S G S STATISTICAL SERVICES	Accounting Services	16,000
92	SALLADAY & DAVIS	Legal Services	45,998
93	SCIENCE APPLICATIONS INTE	Environmental Services	12,143
94	SOFTWARE AG INC	Computer Support Services	120,000
95	SOLID QUALITY LEARNING LLC	Management Services	15,695
96	SOUTH LANDSCAPE ARCHITECTS	Engineering Services	10,097
97	SPHERION STAFFING AND RECRUITI	Employment Services	49,768
98	SPL WORLDGROUP INC	Computer Support Services	119,149
99	ST ALPHONSUS REGIONAL MEDICAL	Environmental Services	10,000
100	STAHMAN, ROBERT W	Legal Services	17,000
101	STATE OF IDAHO FISH & GAME	Environmental Services	50,000
102	STATISTICAL DESIGN	Management Services	25,047
103	STEPTOE & JOHNSON LLP	Legal Services	1,374,110
104	STOEL RIVES LLP	Legal Services	41,137
105	SULLIVAN & CROMWELL	Management Services	213,292
106	SUMMIT BLUE CONSULTING LLC	Consulting Services	21,330
107	SWCA, INC	Environmental Services	165,808
108	TEKSYSTEMS	Computer Support Services	131,015
109	TETRA TECH INC	Computer Support Services	22,783
110	THE LITIGATION DOCUMENT GROUP	Management Services	18,576
111	TOOTHMAN-ORTON ENGINEERING	Engineering Services	51,767
112	TOWERS PERRIN HR SERVICES	Management Services	136,989
113	TREASURE VALLEY LEGAL SERVICES	Legal Services	73,336
114	U S BUREAU OF RECLAMATION	Environmental Services	40,000
115	UNIVERSITY OF IDAHO	Environmental Services	32,330
116	VAN NESS FELDMAN	Legal Services	1,184,465
117	VAN WINKLE ENVIRONMENTAL CONSU	Environmental Services	24,000
118	WEATHER MODIFICATION INC	Cloud Seeding Services	63,099
119	WEBMETHODS	Computer Support Services	14,871
120	WELLENS FARWELL INC	Management Services	560,322
121	WESTERN WEED SERVICE INC	Management Services	23,545
122			
123			
124			
125			
126			
127			
128			
129			
130			
131			
132			
133	**TOTAL**		17,957,200

PROFESSIONAL OR CONSULTATIVE SERVICES

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

Line No.	PAYEE	PREDOMINANT NATURE OF SERVICE	AMOUNT
1	AMERICAN GEOTECHNICS, INC	Engineering Services	7,470
2	BAKER, KEN	Management Services	9,090
3	BUSINESS LEGAL CONSULTING	Legal Services	5,709
4	CALIFORNIA ISO	Environmental Services	6,250
5	CHAVEZ SURVEY RESEARCH, INC	Customer Survey Services	8,864
6	DC ENGINEERING, PC	Engineering Services	7,000
7	E*TRADE	Accounting Services	6,309
8	FALTER PHD, C. MICHAEL	Management Services	7,992
9	FURNITURE PER QUOTE	Management Services	9,248
10	GILBERT, DAN D	Meteorological Services	9,951
11	HISTORY ASSOCIATES, INC.	Consulting Services	7,786
12	INTERMOUNTAIN CLAIMS, INC	Claim Services	6,704
13	KEMA INC	Management Services	5,927
14	MERCER HUMAN RESOURCE CONSULTI	Consulting Services	6,350
15	MOEN, MONICA B	Legal Services	9,124
16	MUSSETTER ENGINEERING INC	Engineering Services	9,983
17	PARADIGM LEARNING, INC	Management Services	8,690
18	PERSONNEL PLUS	Employment Services	7,444
19	PHONE PRO	Consulting Services	8,011
20	PLATEAU SYSTEMS LTD	Management Services	6,200
21	SORRENTO LACTALIS, INC	Management Services	9,258
22	SOUND CHOICE, INC	Management Services	5,157
23	SUSAN STIMPSON	Management Services	6,500
24	UNIVERSAL MANAGEMENT SOLUTIONS	Management Services	7,000
25	UTAH YAMAS CONTROLS	Management Services	5,376
26	YAMAS CONTROLS INTERMOUNTAIN,	Management Services	8,960
27			
28			
29			
30			
31			
32			
33			
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43			
44			
45	**TOTAL**		196,351

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

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

Line No.	Account (a)	Balance at Beginning of year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	$ 57,529	
3	(302) Franchises and Consents	20,553,832	
4	(303) Miscellaneous Intangible Plant	46,571,649	
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	67,183,011	
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	3,982,426	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	793,884,294	
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)	613,086,985	
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
			$ 5,289	(301)	2
			20,729,010	(302)	3
			45,458,188	(303)	4
			66,192,487		5
					6
					7
				(310)	8
				(311)	9
				(312)	10
				(313)	11
				(314)	12
				(315)	13
				(316)	14
			4,751,512	(317)	15
			824,234,217		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
			635,772,428		35
					36
				(340)	37
				(341)	38
				(342)	39
				(343)	40
				(344)	41
				(345)	42
				(345)	43

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

Line No.	Account (a)	Balance at Beginning of year (b)	Additions (c)
44	(346) Misc. Power Plant Equipment		
45	TOTAL Other Production Plant (Enter Total of lines 37 thru 44)	$ 101,232,115	
46	TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 45)	1,508,203,394	
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	24,675,658	
49	(352) Structures and Improvements	31,520,034	
50	(353) Station Equipment	210,231,053	
51	(354) Towers and Fixtures	84,489,667	
52	(355) Poles and Fixtures	64,309,387	
53	(356) Overhead Conductors and Devices	102,055,096	
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices		
56	(359) Roads and Trails	261,954	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	517,542,847	
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	4,341,499	
61	(361) Structures and Improvements	19,267,383	
62	(362) Station Equipment	134,544,631	
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	178,077,556	
65	(365) Overhead Conductors and Devices	91,808,497	
66	(366) Underground Conduit	43,012,125	
67	(367) Underground Conductors and Devices	159,571,691	
68	(368) Line Transformers	289,800,410	
69	(369) Services	48,616,312	
70	(370) Meters	50,592,870	
71	(371) Installations on Customer Premises	2,358,293	
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	3,860,189	
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,025,851,456	
76	5. GENERAL PLANT		
77	(389) Land and Land Rights	8,108,134	
78	(390) Structures and Improvements	59,594,282	
79	(391) Office Furniture and Equipment	34,567,743	
80	(392) Transportation Equipment	47,247,737	
81	(393) Stores Equipment	909,180	
82	(394) Tools, Shop, and Garage Equipment	3,907,749	
83	(395) Laboratory Equipment	9,033,982	
84	(396) Power Operated Equipment	6,762,653	
85	(397) Communication Equipment	26,096,312	
86	(398) Miscellaneous Equipment	2,688,355	
87	SUBTOTAL (Enter Total of lines 77 thru 86)	198,916,128	
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)	198,916,128	
91	TOTAL (Accounts 101 and 106)	3,317,696,836	
92	(102) Electric Plant Purchased		
93	(Less) (102) Electric Plant Sold		
94	(103) Experimental Plant Unclassified		
95			
96	TOTAL Electric Plant in Service	$ 3,317,696,836	

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
			$ 101,426,503		45
			1,561,433,148		46
					47
			26,624,995	(350)	48
			34,464,805	(352)	49
			224,406,655	(353)	50
			104,698,993	(354)	51
			73,602,511	(355)	52
			118,628,677	(356)	53
				(357)	54
				(358)	55
			261,238	(359)	56
				(359.1)	57
			582,687,874		58
					59
			4,177,113	(360)	60
			20,581,394	(361)	61
			144,293,516	(362)	62
				(363)	63
			187,646,959	(364)	64
			99,310,499	(365)	65
			45,493,283	(366)	66
			168,166,353	(367)	67
			320,594,439	(368)	68
			51,079,812	(369)	69
			53,914,672	(370)	70
			2,446,858	(371)	71
				(372)	72
			3,916,181	(373)	73
				(374)	74
			1,101,621,080		75
					76
			8,229,314	(389)	77
			63,800,301	(390)	78
			35,424,379	(391)	79
			53,102,346	(392)	80
			996,702	(393)	81
			4,090,231	(394)	82
			9,489,976	(395)	83
			8,077,988	(396)	84
			24,014,386	(397)	85
			2,806,494	(398)	86
			210,032,117		87
				(399)	88
				(399.1)	89
			210,032,117		90
			3,521,966,706		91
				(102)	92
				(102)	93
				(371)	94
					95
			$ 3,521,966,706		96

ELECTRIC OPERATING REVENUES (Account 400)

1. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
2. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
3. If previous year (columns (c), (e) and (g), are not derived from previously reported figures, explain any inconsistencies in a footnote.

No.	(a)	OPERATING REVENUES Amount for Current Year (b)	Amount for Previous Year (c)
1	Sales of Electricity		
2	(440) Residential Sales	$ 297,428,947	$ 289,068,594
3	(442) Commercial and Industrial Sales		
4	Small (or Commercial)(See Instr. 4) (1)	245,919,592	221,723,109
5	Large (or Industrial)(See Instr. 4) (2)	92,303,177	93,623,913
6	(444) Public Street and Highway Lighting	2,374,374	2,290,770
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	638,026,089 *	606,706,387
11	(447) Sales for Resale - Opportunity....Non-Firm Only	159,135,233	242,715,342
12	TOTAL Sales of Electricity	797,161,322	849,421,730
13	(449.1) Provision for Rate Refunds	(1,075,534)	(1,211,251)
14	TOTAL Revenue Net of Provision for Refunds	796,085,788	848,210,479
15	**Other Operating Revenues**		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	3,996,236	5,368,289
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	17,049,167	15,142,580
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	24,347,160	7,748,184
22			
23			
24			
25	TOTAL Other Operating Revenues	45,392,562	28,259,054
26	TOTAL Electric Operating Revenues	$ 841,478,350	$ 876,469,532

(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
5,027,203,909	4,868,383,891	383,992	374,527	2
				3
5,622,131,528	5,170,019,354	73,726	71,472	4
3,170,394,452	3,170,158,215	118	122	5
28,637,063	27,402,244	992	768	6
				7
				8
				9
13,848,366,952 **	13,235,963,704	458,828	446,889	10
2,603,995,368	5,492,528,583	N/A	N/A	11
16,452,362,320	18,728,492,287	458,828	446,889	12
				13

* Includes $ 4,657,755 unbilled revenues.

** Includes 13,733,012 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	$ 1,585,144	$ 1,621,185
5	(501) Fuel	108,989,376	101,451,974
6	(502) Steam Expenses	6,491,790	6,706,052
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr		
9	(505) Electric Expenses	2,002,446	1,362,769
10	(506) Miscellaneous Steam Power Expenses	7,681,857	7,708,765
11	(507) Rents	281,610	235,366
12	(509) Allowances		
13	TOTAL Operation (Enter Total of lines 4 thru 12)	127,032,223	119,086,112
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	2,456,682	2,390,796
16	(511) Maintenance of Structures	618,172	387,046
17	(512) Maintenance of Boiler Plant	13,885,052	14,509,643
18	(513) Maintenance of Electric Plant	5,395,860	4,183,656
19	(514) Maintenance of Miscellaneous Steam Plant	5,650,640	4,331,618
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	28,006,406	25,802,758
21	TOTAL Power Production Expenses-Steam Power (Enter Total of lines 13 and 20).	155,038,629	144,888,870
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	4,984,055	4,280,591
45	(536) Water for Power	4,814,932	4,674,353
46	(537) Hydraulic Expenses	9,016,462	7,818,109
47	(538) Electric Expenses	1,323,535	1,312,063
48	(539) Miscellaneous Hydraulic Power Generation Expenses	2,690,247	2,278,711
49	(540) Rents	399,555	387,654
50	TOTAL Operation (Enter Total of lines 44 thru 49)	23,228,787	20,751,482

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	$ 1,785,723	$ 1,771,573
54	(542) Maintenance of Structures	1,220,450	1,129,692
55	(543) Maintenance of Reservoirs, Dams, and Waterways	515,125	896,199
56	(544) Maintenance of Electric Plant	1,988,155	2,022,387
57	(545) Maintenance of Miscellaneous Hydraulic Plant	2,630,881	3,042,284
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	8,140,333	8,862,134
59	TOTAL Power Production Expenses-Hydraulic Power (Enter Total of lines 50 and 58	31,369,119	29,613,616
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	325,262	305,152
63	(547) Fuel	18,492,527	7,075,143
64	(548) Generation Expenses	363,281	274,538
65	(549) Miscellaneous Other Power Generation Expenses	442,565	281,369
66	(550) Rents	0	-
67	TOTAL Operation (Enter Total of lines 62 thru 66)	19,623,635	7,936,201
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	0	164
70	(552) Maintenance of Structures	209,865	167,535
71	(553) Maintenance of Generating and Electric Plant	40,597	117,540
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	614,836	371,585
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	865,298	656,823
74	TOTAL Power Production Expenses-Other Power (Enter Total of lines 67 and 73)	20,488,934	8,593,024
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	288,699,422	267,452,726
77	(556) System Control and Load Dispatching	73,778	72,080
78	(557) Other Expenses	(112,995,170)	(25,848,541)
79	TOTAL Other Power Supply Expenses (Enter Total of lines 76 thru 78)	175,778,030	241,676,264
80	TOTAL Power Production Expenses (Enter Total of lines 21, 41, 59, 74, and 79)	382,674,713	424,771,774
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	1,987,843	2,163,362
84	(561) Load Dispatching	2,806,393	3,010,532
85	(562) Station Expenses	1,491,967	1,596,812
86	(563) Overhead Line Expenses	784,669	738,876
87	(564) Underground Line Expenses		
88	(565) Transmission of Electricity by Others	9,936,576	7,207,592
89	(566) Miscellaneous Transmission Expenses	529,755	230,883
90	(567) Rents	990,555	982,438
91	TOTAL Operation (Enter Total of lines 83 thru 90)	18,527,758	15,930,496
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	376,412	393,040
94	(569) Maintenance of Structures	387,193	169,741
95	(570) Maintenance of Station Equipment	2,473,911	2,480,807
96	(571) Maintenance of Overhead Lines	1,987,795	1,917,736
97	(572) Maintenance of Underground Lines		
98	(573) Maintenance of Miscellaneous Transmission Plant	2,151	26,623
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	5,227,462	4,987,948
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	23,755,220	20,918,444
101	3. DISTRIBUTION EXPENSES		
102	Operation		
103	(580) Operation Supervision and Engineering	3,141,021	2,853,198

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
104	3. DISTRIBUTION EXPENSES (Continued)		
105	(581) Load Dispatching	$ 2,906,722	$ 2,847,658
106	(582) Station Expenses	1,066,301	1,091,619
107	(583) Overhead Line Expenses	3,172,327	3,544,944
108	(584) Underground Line Expenses	2,085,453	2,008,479
109	(585) Street Lighting and Signal System Expenses	141,411	146,732
110	(586) Meter Expenses	4,332,721	4,122,897
111	(587) Customer Installations Expenses	1,227,727	1,028,502
112	(588) Miscellaneous Distribution Expenses	5,187,236	5,227,173
113	(589) Rents	604,482	140,239
114	TOTAL Operation (Enter Total of lines 103 thru 113)	23,865,402	23,011,442
115	Maintenance		
116	(590) Maintenance Supervision and Engineering	246,198	208,690
117	(591) Maintenance of Structures	0	-
118	(592) Maintenance of Station Equipment	3,322,976	2,659,704
119	(593) Maintenance of Overhead Lines	11,557,647	10,129,328
120	(594) Maintenance of Underground Lines	1,328,521	1,096,396
121	(595) Maintenance of Line Transformers	154,268	530,254
122	(596) Maintenance of Street Lighting and Signal Systems	453,194	674,996
123	(597) Maintenance of Meters	888,231	861,056
124	(598) Maintenance of Miscellaneous Distribution Plant	114,582	133,375
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	18,065,618	16,293,800
126	TOTAL Distribution Expenses (Enter Total of lines 114 and 125)	41,931,019	39,305,242
127	4. CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision	435,360	512,985
130	(902) Meter Reading Expenses	5,146,950	4,958,009
131	(903) Customer Records and Collection Expenses	7,866,032	9,753,911
132	(904) Uncollectible Accounts	1,876,639	2,770,604
133	(905) Miscellaneous Customer Accounts Expenses	320	356
134	TOTAL Customer Accounts Expenses (Enter Total of lines 129 thru 133)	15,325,300	17,995,866
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision	299,100	281,641
138	(908) Customer Assistance Expenses	21,710,324	8,822,366
139	(909) Informational and Instructional Expenses	0	192
140	(910) Miscellaneous Customer Service and Informational Expenses	876,111	826,658
141	TOTAL Cust. Service and Informational Expenses (Enter Total of lines 137 thru 140)	22,885,534	9,930,857
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	46,724,352	45,701,139
152	(921) Office Supplies and Expenses	16,697,245	13,696,615
153	(Less) (922) Administrative Expenses Transferred-Credit	(26,005,639)	(27,386,005)

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	$ 10,542,564	$ 7,610,977
156	(924) Property Insurance	2,957,019	2,744,172
157	(925) Injuries and Damages	5,113,519	4,811,467
158	(926) Employee Pensions and Benefits	26,159,168	27,309,084
159	(927) Franchise Requirements	1,200	2,000
160	(928) Regulatory Commission Expenses	5,332,170	(316,513)
161	(929) Duplicate Charges-Cr		
162	(930.1) General Advertising Expenses	487,897	100,217
163	(930.2) Miscellaneous General Expenses	3,282,233	1,775,497
164	(931) Rents	10,731	3,705
165	TOTAL Operation (Enter Total of lines 151 thru 164)	91,302,458	76,052,354
166	Maintenance		
167	(935) Maintenance of General Plant	3,498,047	3,673,670
168	TOTAL Admin and General Expenses (Enter Total of lines 165-167)	94,800,506	79,726,024
169	TOTAL Elec Op and Maint Exp (Total of 80, 100, 126, 134, 141, 148, 168)	$ 581,372,293	$ 592,648,206

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, 2007	December 31, 2006
2	Total Regular Full-Time Employees	1,968	1,871
3	Total Part-Time and Temporary Employees	29	38
4	Total Employees	1,997	1,909