

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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IDaho Power
UTILITIES COMMISSION

FERC FINANCIAL REPORT

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

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

Exact Legal Name of Respondent (Company)

Idaho Power Company

Year/Period of Report

End of 2005/Q4



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UTILITIES COMMISSION

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, 2005, 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, 2005, 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, 2005, and the results of its operations and its cash flows for the year ended December 31, 2005, 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

March 6, 2006
Boise, Idaho

INSTRUCTIONS FOR FILING FERC FORMS 1, 1-F and 3-Q

GENERAL INFORMATION

I Purpose

Form 1 is an annual regulatory support requirement under 18 CFR 141.1 for Major public utilities, licensees and others. Form 1-F is an annual regulatory support requirement under 18 CFR 141.2 for Nonmajor public utilities, licensees and others. Form 3-Q is a quarterly regulatory support requirement which supplements Forms 1 and 1-F under 18 CFR 141.400. The reports are designed to collect financial and operational information from major and nonmajor electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be a 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 CFR 101), must submit Form 1 as prescribed in 18 CFR Part 141.1. Each Nonmajor electric utility, licensee or other must submit Form 1-F as prescribed in 18 CFR Part 141.2. Each Major and Nonmajor electric utility licensee or other, must submit Form 3-Q as prescribed in 18 CFR Part 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).

Nonmajor means having in each of the three previous calendar years, total annual sales of 10,000 megawatt hours or more

III. What and Where to Submit

- (a) Submit Forms 1, 1-F and 3-Q electronically through the Form 1/3-Q Submission Software. Retain one copy of each report for your files.
- (b) Respondents may submit the Corporate Officer Certification electronically, or file/mail an original signed Corporate Officer Certification to:

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

(c) Submit, immediately upon publication, four (4) copies of the latest annual report to stockholders and any annual financial or statistical report regularly prepared and distributed to bondholders, security analysts, or industry associations. (Do not include monthly and quarterly reports. Indicate by checking the appropriate box on Form 1, Page 4, List of Schedules, if the reports to stockholders will be submitted or if no annual report to stockholders is prepared.) Mail these reports to the address in III(c) above.

(d) For the Annual CPA certification, submit with the original submission, or within 30 days after the filing date for Form 1, a letter or report (not applicable to respondents classified as Class C or Class D prior to January 1, 1984):

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

(ii) 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 CFR 158.10-158.12 for specific qualifications.)

Reference	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

Insert the letter or report immediately following the cover sheet. When submitting after the filing date for this form, send the letter or report to the address indicated at III (b). Use the following form for the letter or report unless unusual circumstances or conditions, explained in the Letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

GENERAL INFORMATION (continued)

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.

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

(d) Federal, State and Local Governments and other authorized users may obtain additional blank copies to meet their requirements free of charge from: Public Reference and Files Maintenance Branch Federal Energy Regulatory Commission 888 First Street, NE, Room 2A ED-12.2 Washington, DC 20426 (202).502-8371

IV. When to Submit:

Submit Form 1 according to the filing dates contained in section 18 CFR 141.1 of the Commission's regulations. Submit Form 1-F according to the filing dates contained in section 18 CFR 141.2 of the Commission's regulations. Submit Form 3-Q according to the filing dates contained in section 18 CFR 141.400 of the Commission's regulations.

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the 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. public reporting burden for the Form 1-F collection of information is estimated to average 112 hours per response. The public reporting burden for the 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: Mr. Michael Miller, ED-30); 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 101) (U.S. of A.). Interpret all accounting words and phrases in accordance with the U. S. of A.
- 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 1/3-Q software and send a letter identifying which pages in the form have been revised. Send the letter to the Office of the Secretary.
- 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 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.

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 wit: ... (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 on 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 forebay reservoirs directly connected therewith, the primary line or Lines transmitting power therefrom 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 ;he 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 my prescribe the manner and form in which such reports shall 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 *form or 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

"Sec. 315. (a) Any licensee or public utility which willfully fails, within the time prescribed by the Commission, to comply with any order of the Commission, to file any report required under this Act or any rule or regulation of the Commission thereunder, to submit any information of document required by the Commission in the course of an investigation conducted under this Act shall forfeit to the United States an amount not exceeding \$1,000 to be fixed by the Commission after notice and opportunity for hearing "

**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 <u>2005/Q4</u>	
03 Previous Name and Date of Change (if name changed during year) Idaho Power Company / /		
04 Address of Principal Office at End of Period (Street, City, State, Zip Code) 1221 W Idaho Street, P.O. Box 70 Boise, ID 83707-0070		
05 Name of Contact Person Darrel Anderson	06 Title of Contact Person Senior VP of Admin Ser & CFO	
07 Address of Contact Person (Street, City, State, Zip Code) 1221 W Idaho Street, P.O. Box 70 Boise, ID 83707-0070		
08 Telephone of Contact Person, Including Area Code (208) 388-2650	09 This Report Is (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	10 Date of Report (Mo, Da, Yr) 04/18/2006

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name Darrel Anderson	03 Signature Darrel Anderson	04 Date Signed (Mo, Da, Yr) / /
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) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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LIST OF SCHEDULES (Electric Utility)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Important Changes During the Year	108-109	
7	Comparative Balance Sheet	110-113	
8	Statement of Income for the Year	114-117	
9	Statement of Retained Earnings for the Year	118-119	
10	Statement of Cash Flows	120-121	
11	Notes to Financial Statements	122-123	
12	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
13	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
14	Nuclear Fuel Materials	202-203	None
15	Electric Plant in Service	204-207	
16	Electric Plant Leased to Others	213	None
17	Electric Plant Held for Future Use	214	
18	Construction Work in Progress-Electric	216	
19	Accumulated Provision for Depreciation of Electric Utility Plant	219	
20	Investment of Subsidiary Companies	224-225	
21	Materials and Supplies	227	
22	Allowances	228-229	None
23	Extraordinary Property Losses	230	
24	Unrecovered Plant and Regulatory Study Costs	230	
25	Other Regulatory Assets	232	
26	Miscellaneous Deferred Debits	233	
27	Accumulated Deferred Income Taxes	234	
28	Capital Stock	250-251	
29	Other Paid-in Capital	253	
30	Capital Stock Expense	254	
31	Long-Term Debit	256-257	
32	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
33	Taxes Accrued, Prepaid and Charged During the Year	262-263	
34	Accumulated Deferred Investment Tax Credits	266-267	
35	Other Deferred Credits	269	
36	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of <u>2005/Q4</u>
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LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Accumulated Deferred Income Taxes-Other Property	274-275	
38	Accumulated Deferred Income Taxes-Other	276-277	
39	Other Regulatory Liabilities	278	
40	Electric Operating Revenues	300-301	
41	Sales of Electricity by Rate Schedules	304	
42	Sales for Resale	310-311	
43	Electric Operation and Maintenance Expenses	320-323	
44	Purchased Power	326-327	
45	Transmission of Electricity for Others	328-330	
46	Transmission of Electricity by Others	332	
47	Miscellaneous General Expenses-Electric	335	
48	Depreciation and Amortization of Electric Plant	336-337	
49	Regulatory Commission Expenses	350-351	
50	Research, Development and Demonstration Activities	352-353	
51	Distribution of Salaries and Wages	354-355	
52	Common Utility Plant and Expenses	356	None
53	Purchase and Sale of Ancillary Services	398	None
54	Monthly Transmission System Peak Load	400	
55	Electric Energy Account	401	
56	Monthly Peaks and Output	401	
57	Steam Electric Generating Plant Statistics	402-403	
58	Hydroelectric Generating Plant Statistics	406-407	
59	Pumped Storage Generating Plant Statistics	408-409	None
60	Generating Plant Statistics Pages	410-411	
61	Transmission Line Statistics Pages	422-423	
62	Transmission Lines Added During the Year	424-425	
63	Substations	426-427	
64	Footnote Data	450	
	<p>Stockholders' Reports Check appropriate box:</p> <p><input checked="" type="checkbox"/> Four copies will be submitted</p> <p><input type="checkbox"/> No annual report to stockholders is prepared</p>		

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of <u>2005/Q4</u>
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GENERAL INFORMATION

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

Darrel Anderson Senior Vice President of Administration 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) No

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of <u>2005/Q4</u>
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CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the respondent 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 beneficiaries 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

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Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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CORPORATIONS CONTROLLED BY RESPONDENT

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

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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OFFICERS

- 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.
- 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 - Retired	Jan B. Packwood	630,000
3			
4	President, Chief Executive and Chief Operating Officer	J. LaMont Keen	400,000
5			
6	Sr Vice President, Power Supply	James C. Miller	270,000
7			
8	Sr Vice President, General Counsel and Secretary	Thomas Saldin	250,000
9			
10	Sr Vice President, Administrative Services & CFO	Darrel T Anderson	240,000
11			
12	Vice President and Chief Information Officer	A. Bryan Kearny	193,000
13			
14	Sr Vice President, Delivery	Dan Minor	205,000
15			
16	Vice President, Human Resources	Luci McDonald	160,000
17			
18	Vice President, Regulatory Affairs	Ric Gale	175,000
19			
20	Vice President, Public Affairs	Greg Panter	160,000
21			
22	Vice President and Treasurer	Dennis Gribble	155,000
23			
24	Vice President, Finance and Chief Risk Officer	Lori Smith	155,000
25			
26	Vice President, Delivery Engineering and Operation	Lisa Grow	135,000
27			
28	Vice President, Customer Service and Regional Ops	Warren Kline	140,000
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Name of Respondent Idaho Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report 2005/Q4
FOOTNOTE DATA			

Schedule Page: 104 Line No.: 2 Column: a

Retired as Chief Executive Officer November 17, 2005

Schedule Page: 104 Line No.: 4 Column: a

Appointed Chief Executive Officer November 17, 2005.
Relinquished Chief Operating Officer November 17, 2005.

Schedule Page: 104 Line No.: 26 Column: a

Appointed to newly created position July 2005.

Schedule Page: 104 Line No.: 28 Column: a

Appointed to newly created position July 2005.

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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	P.O. Box 2080, Cody Wyoming 82414
2		
3	Jack K. Lemley	Lemley & Associates, Inc.
4		1508 N. 13th, Boise, Idaho 83702
5		
6	Gary Michael ***	P.O. Box 1718 Boise Idaho 83701
7		
8	Jon H. Miller ***	P.O. Box 1557, Boise, Idaho 83701
9		
10	Peter S. O'Neill ***	O'Neill Enterprises, Inc.
11		871 E. Parkcenter Blvd., Boise, Idaho 83706
12		
13	Jan B. Packwood ** President and CEO (Retired)	Idaho Power Company, 1221 W. Idaho Street,
14		P.O. Box 70, Boise, Idaho 83707-0070
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	Robert A. Tinstman ***	4433 W. Quail Point Court, Boise, Idaho, 83703
20		
21	Richard G. Reiten	NW Natural 220 NW 2nd Ave - 13th floor, Portland, Oregon 97209
22		
23	Thomas Wilford	Alscoff Inc, 501 Baybrook Court Boise, Idaho 83706
24		
25	Joan Smith	2309 S.W. Avenue, No. 1141, Portland, OR 97201
26		
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Name of Respondent Idaho Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report 2005/Q4
FOOTNOTE DATA			

Schedule Page: 105 Line No.: 13 Column: a
 Relinquished position as Chief Executive Officer November 17, 2005

Schedule Page: 105 Line No.: 16 Column: a
 Appointed Chief Executive Officer November 17, 2005.
 Relinquished Chief Operating Officer November 17, 2005.

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report 04/18/2006	Year/Period of Report End of <u>2005/Q4</u>
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IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

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

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

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Idaho Power Company	(1) <input checked="" type="checkbox"/> An Original	(Mo, Da, Yr)	
	(2) <input type="checkbox"/> A Resubmission	04/18/2006	2005/Q4
IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)			

1. Relicensing costs closed to account 302 - \$3,254,971 for Mid-Snake Power Plant-Idaho.

2. None

3. None

4. None

5. New Transmission Lines:

Eagle - Star 138 Kv line #464 6.35 miles

Eckert - 138 Kv tap line #412

Bennett Mtn Power Plant to rattlesnake sub #716 4.48 miles

1 Transmission station - Horse Flat transmission station

3 Distribution stations:

Ten Mile

Lake Fork

Rattlesnake

6. Issued \$60 million of 5.30% First Mortgage Bonds maturing 8/26/35. Commission authorization for IPUC IPC-E-04-22 OPUC UF-4211, and WPSC 2005-ES-04-27.

7. None

8. On December 29, 2005 a general wage increase of 3.0%.

9. See pages 123.9 to 123.17

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 2005. Top ten institutional shareholders list saw the addition of Lord, Abbett & Company, Prenza Investment Management, NWQ Investment Management and ICM Asset Management. Leaving the top ten list of institutional shareholders was Martingale Asset Management, TIAA-CREF Investestment, Smith Barney Asset Management and Bear Stearns & Company.

14. None

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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	3,479,972,995	3,327,451,494
3	Construction Work in Progress (107)	200-201	149,814,313	151,651,719
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		3,629,787,308	3,479,103,213
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	1,364,640,116	1,316,124,554
6	Net Utility Plant (Enter Total of line 4 less 5)		2,265,147,192	2,162,978,659
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)		2,265,147,192	2,162,978,659
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)		922,349	828,002
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	43,512,409	36,544,480
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)		1,025,159	32,458,340
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		27,337,666	27,507,094
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	0
31	Long-Term Portion of Derivative Assets - Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		72,797,583	97,337,916
33	CURRENT AND ACCRUED ASSETS			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		583,874	359,186
36	Special Deposits (132-134)		510,000	0
37	Working Fund (135)		42,750	57,457
38	Temporary Cash Investments (136)		48,687,442	17,236,000
39	Notes Receivable (141)		10,522,187	11,863,100
40	Customer Accounts Receivable (142)		49,830,007	45,440,589
41	Other Accounts Receivable (143)		6,860,636	5,201,303
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		833,238	1,363,426
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		637,084	1,297,952
45	Fuel Stock (151)	227	11,494,190	6,450,733
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	28,705,792	25,378,777
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of <u>2005/Q4</u>
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COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	1,745,428	685,830
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)		17,532,437	28,448,966
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		28,192	52,040
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		38,905,298	33,832,290
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		244,432	87,506
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	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)		215,496,511	175,028,303
68	DEFERRED DEBITS			
69	Unamortized Debt Expenses (181)		11,128,248	7,741,547
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	418,241,190	438,780,828
73	Prelim. Survey and Investigation Charges (Electric) (183)		187,483	91,953
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)		300,821	12,057
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	82,087,452	83,272,850
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		14,032,339	15,193,036
82	Accumulated Deferred Income Taxes (190)	234	103,660,136	72,712,115
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		629,637,669	617,804,386
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		3,183,078,955	3,053,149,264

Name of Respondent Idaho Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Rresubmission	Date of Report (mo, da, yr) 04/18/2006	Year/Period of Report end of 2005/Q4
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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	483,707,552	483,707,552
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	321,453,283	309,178,039
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	39,802,850	30,928,808
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)	-3,425,324	-887,774
16	Total Proprietary Capital (lines 2 through 15)		937,318,466	918,706,730
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	955,460,000	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	31,585,000	31,585,000
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		3,325,109	3,135,446
24	Total Long-Term Debt (lines 18 through 23)		983,719,891	983,909,554
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		1,191,411	1,797,494
29	Accumulated Provision for Pensions and Benefits (228.3)		13,361,444	10,592,032
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		0	400,102
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)		10,079,335	9,287,789
35	Total Other Noncurrent Liabilities (lines 26 through 34)		24,632,190	22,077,417
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		77,435,649	72,530,597
39	Notes Payable to Associated Companies (233)		10,101,115	20,469,707
40	Accounts Payable to Associated Companies (234)		152,888	278,488
41	Customer Deposits (235)		1,103,299	1,000,352
42	Taxes Accrued (236)	262-263	72,183,706	40,280,158
43	Interest Accrued (237)		14,104,406	13,742,553
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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 column in 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	849,075,951	800,822,106		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	505,272,123	523,328,322		
5	Maintenance Expenses (402)	320-323	59,538,848	58,404,718		
6	Depreciation Expense (403)	336-337	92,933,330	90,986,890		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	8,574,137	10,050,731		
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)		16,191,442	19,944		
13	(Less) Regulatory Credits (407.4)		4,820,743	18,949,682		
14	Taxes Other Than Income Taxes (408.1)	262-263	20,856,185	19,090,214		
15	Income Taxes - Federal (409.1)	262-263	64,853,588	16,305,814		
16	- Other (409.1)	262-263	8,931,316	7,273,792		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	24,279,913	28,170,120		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	58,648,054	45,142,816		
19	Investment Tax Credit Adj. - Net (411.4)	266	1,950,116	-952,821		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)		591	-2,071		
22	(Less) Gains from Disposition of Allowances (411.8)		1,173,359	158,330		
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)		738,716,710	688,402,102		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		110,359,241	112,420,004		

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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 purchases, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stockholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		Line No.
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	
						1
849,075,951	800,822,106					2
						3
505,272,123	523,328,322					4
59,538,848	58,404,718					5
92,933,330	90,986,890					6
						7
8,574,137	10,050,731					8
-22,723	-22,723					9
						10
						11
16,191,442	19,944					12
4,820,743	18,949,682					13
20,856,185	19,090,214					14
64,853,588	16,305,814					15
8,931,316	7,273,792					16
24,279,913	28,170,120					17
58,648,054	45,142,816					18
1,950,116	-952,821					19
						20
591	-2,071					21
1,173,359	158,330					22
						23
						24
738,716,710	688,402,102					25
110,359,241	112,420,004					26

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STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL		Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
			Current Year (c)	Previous Year (d)		
27	Net Utility Operating Income (Carried forward from page 114)		110,359,241	112,420,004		
28	Other Income and Deductions					
29	Other Income					
30	Nonutility Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		2,986,557	3,427,754		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		2,553,933	3,388,329		
33	Revenues From Nonutility Operations (417)		125,826	110,035		
34	(Less) Expenses of Nonutility Operations (417.1)		285,293	279,748		
35	Nonoperating Rental Income (418)		-1,036	-2,136		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	8,874,042	8,190,247		
37	Interest and Dividend Income (419)		3,192,922	2,412,553		
38	Allowance for Other Funds Used During Construction (419.1)		4,950,151	3,904,027		
39	Miscellaneous Nonoperating Income (421)		5,069,732	5,624,756		
40	Gain on Disposition of Property (421.1)		27,521	469,258		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		22,386,489	20,468,417		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		106,328	7,207		
44	Miscellaneous Amortization (425)	340				
45	Donations (426.1)	340	533,964	538,360		
46	Life Insurance (426.2)		95,508	-671,031		
47	Penalties (426.3)					
48	Exp. for Certain Civic, Political & Related Activities (426.4)		351,382	550,041		
49	Other Deductions (426.5)		4,637,585	13,923,708		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		5,724,767	14,348,285		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	37,228	38,712		
53	Income Taxes-Federal (409.2)	262-263	1,042,859	144,957		
54	Income Taxes-Other (409.2)	262-263	244,977	43,666		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	1,213,137	1,586,407		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	1,817,329	5,482,592		
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)		720,872	-3,668,850		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		15,940,850	9,788,982		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		53,339,531	50,317,585		
63	Amort. of Debt Disc. and Expense (428)		1,262,733	1,188,137		
64	Amortization of Loss on Reaquired Debt (428.1)		1,160,697	1,192,994		
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	386,020	256,468		
68	Other Interest Expense (431)	340	1,103,151	1,598,490		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		2,790,871	2,952,809		
70	Net Interest Charges (Total of lines 62 thru 69)		54,461,261	51,600,865		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		71,838,830	70,608,121		
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)		71,838,830	70,608,121		

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of <u>2005/Q4</u>
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STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		307,634,073	296,452,895
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		62,964,788	62,417,874
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				(2,934,959)
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			(2,934,959)
30	Dividends Declared-Common Stock (Account 438)			
31	\$2.50 Par Value		-50,689,544	(46,413,448)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-50,689,544	(46,413,448)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		319,909,317	309,522,362

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		1,543,966	1,543,966
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		1,543,966	1,543,966
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		321,453,283	311,066,328
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		30,928,808	22,738,561
50	Equity in Earnings for Year (Credit) (Account 418.1)		8,874,042	8,190,247
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)		39,802,850	30,928,808

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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)	71,838,830	70,608,121
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	92,933,330	90,986,890
5	Amortization of (see note)	12,986,104	17,564,230
6			
7			
8	Deferred Income Taxes (Net)	-34,972,335	-21,373,450
9	Investment Tax Credit Adjustment (Net)	1,950,117	-952,821
10	Net (Increase) Decrease in Receivables	4,885,165	-4,049,547
11	Net (Increase) Decrease in Inventory	-9,430,070	-587,583
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	34,355,903	14,699,394
14	Net (Increase) Decrease in Other Regulatory Assets	18,112,357	17,122,666
15	Net Increase (Decrease) in Other Regulatory Liabilities	-10,837,689	-334,354
16	(Less) Allowance for Other Funds Used During Construction	4,950,151	3,904,027
17	(Less) Undistributed Earnings from Subsidiary Companies	8,874,042	9,127,301
18	Other (provide details in footnote):	6,667,692	15,690,324
19			
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	176,665,211	186,342,542
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-183,073,929	-187,333,369
27	Gross Additions to Nuclear Fuel		
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant	-200,675	
30	(Less) Allowance for Other Funds Used During Construction	2,790,871	2,952,809
31	Other: Sale of Emission Allowance	70,757,625	
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-115,307,850	-190,286,178
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		831
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)	-85,333,932	-295,355,514
45	Proceeds from Sales of Investment Securities (a)	120,025,599	266,331,185

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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	1,116,424	-39,409
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-79,499,759	-219,349,085
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	60,000,000	105,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		11,448,683
67	Other (provide details in footnote):		85,920,000
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	60,000,000	202,368,683
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-60,000,000	-50,000,000
74	Preferred Stock		-52,350,828
75	Common Stock		
76	Other (provide details in footnote): Other long-term assets	-4,445,891	-2,119,881
77			
78	Net Decrease in Short-Term Debt (c)	-10,368,593	
79			
80	Dividends on Preferred Stock		-4,823,248
81	Dividends on Common Stock	-50,689,545	-46,413,448
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-65,504,029	46,661,278
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	31,661,423	13,654,735
87			
88	Cash and Cash Equivalents at Beginning of Period	17,652,643	3,997,908
89			
90	Cash and Cash Equivalents at End of period	49,314,066	17,652,643

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Name of Respondent Idaho Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report 2005/Q4
FOOTNOTE DATA			

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

Amortization	12 Months Ended 12/31/2005	
Plant		8,551,414
Regulatory Assets		4,314,589
Unamortized Debt Expense		2,309,764
Unamortized Discount		(189,663)
Other		
		14,986,104

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

Cash Flow from Operating Activites (Other)	12 Months Ended 12/31/2005	
Unbilled Revenues		(5,073,008)
Other Current Liabilities		1,269,138
Other long-term Assets		(697,657)
Other long-term Liabilities		11,841,225
Gain on Sale of Assets		(778,334)
Loss on sale of non-utility assets		106,328
		6,667,692

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report 04/18/2006	Year/Period of Report End of <u>2005/Q4</u>
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NOTES TO FINANCIAL STATEMENTS

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

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

Name of Respondent	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report 2005/Q4
Idaho Power Company			
NOTES TO FINANCIAL STATEMENTS (Continued)			

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Nature of Business

Idaho Power Company (IPC) a wholly-owned subsidiary of 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 Federal Energy Regulatory Commission (FERC) and the State regulatory commissions of Idaho and Oregon. IPC is the parent of Idaho Energy Resources Co. (IERCO), a joint venturer in Bridger Coal Company, which supplies coal to the Jim Bridger generating plant owned in part by IPC. IERCO is not consolidated for FERC Form-1 reporting purposes. IDACOMM a wholly-owned subsidiary of IDACORP is a provider of telecommunications services and commercial Internet services.

Basis of Presentation

These financial statements were prepared in accordance with the accounting requirements of FERC as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than generally accepted accounting principles.

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 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.

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 2.91 percent in 2005 and 2.96 percent in 2004.

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 Statement of Financial Accounting Standards (SFAS) 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." 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 asset 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 2005 and 2004 were 7.4 percent and 6.9 percent. IPC's reductions to interest expense for AFDC were \$3 million annually for 2005 and 2004. Other income included \$5 million and \$4 million for 2005 and 2004, respectively.

Revenues

Name of Respondent Idaho Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report 2005/Q4
NOTES TO FINANCIAL STATEMENTS (Continued)			

IPC accrues unbilled revenues for electric services delivered to customers but not yet billed at month-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.

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.

Power Cost Adjustment

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 or over-recovered portion, is then included in the calculation of the next year's PCA.

Income Taxes

The liability method of computing deferred taxes is used on all temporary differences between the book and tax basis of assets and liabilities and deferred tax assets and liabilities are adjusted for enacted changes in tax laws or rates. 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

Stock-based employee compensation is accounted for under the recognition and measurement principles of Accounting Principles Board (APB) Opinion 25, "Accounting for Stock Issued to Employees," and related interpretations. Grants of performance shares are reflected in net income based on the market value at the award date, or the period-end price for shares not yet vested. Grants of restricted stock are reflected in net income based on the market value on the grant date. No stock-based employee compensation cost is reflected in net income for stock options, as all options granted had an exercise price equal to the market value of the underlying common stock on the date of grant. IPC has adopted the disclosure only provision of SFAS 123, "Accounting for Stock-Based Compensation."

The following table illustrates the effect on net income and EPS if the fair value recognition provisions of SFAS 123 had been applied to stock-based employee compensation:

	2005	2004
	(thousands of dollars except for per share amounts)	
Net income, as reported	\$ 71,839	\$ 70,608
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	108	276
Deduct: Stock-based employee compensation expense determined under fair value based method for all awards, net		

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of related tax effects	568	977
Pro forma net income	\$ 71,379	\$ 69,907

For purposes of these pro forma calculations, the estimated fair value of the options, restricted stock and performance shares is amortized to expense over the vesting period. The fair value of the restricted stock and performance shares is the market price of the stock on the date of grant. The fair value of an option award is estimated at the date of grant using a binomial option-pricing model. Expense related to forfeited options is reversed in the period in which the forfeit occurs. For more information see Note 9.

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.

Comprehensive Income

Comprehensive income includes net income, unrealized holding gains and losses on marketable securities, IPC's proportionate share of unrealized holding gains and losses on marketable securities held by an equity investee and the changes in additional minimum liability under 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:

	2005	2004
	(thousands of dollars)	
Unrealized holding gains on securities	\$ 2,725	\$ 4,538
Minimum pension liability adjustment	(6,150)	(5,426)
Total	\$ (3,425)	\$ (888)

New Accounting Pronouncements

SFAS 123(R): In December 2004, the FASB issued SFAS 123 (revised 2004), "Share-Based Payment," which revises SFAS 123 and supersedes APB 25 and its related interpretive guidance. SFAS 123(R) establishes standards for the accounting for transactions in which an entity exchanges its equity instruments for goods or services. It also addresses transactions in which an entity incurs liabilities in exchange for goods or services that are based on the fair value of the entity's equity instruments or that may be settled by the issuance of those equity instruments. SFAS 123(R) focuses primarily on accounting for transactions in which an entity obtains employee services in share-based payment transactions.

Under the provisions of SFAS 123(R), the fair value of all stock options must be reported as an expense on the financial statements. IPC currently applies the measurement provisions of APB 25 and the disclosure-only provisions of SFAS 123. SFAS 123(R) also changes other measurement, timing and disclosure rules relating to share-based payments.

In March 2005, the staff of the Securities and Exchange Commission issued Staff Accounting Bulletin (SAB) 107 to provide additional guidance regarding the application of SFAS 123(R). SAB 107 permits registrants to choose an appropriate valuation technique or model to estimate the fair value of share options, assuming consistent application, and provides guidance for the development of assumptions used in the valuation process. Additionally, SAB 107 discusses disclosures to be made under "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the registrants' periodic reports.

Based upon Securities and Exchange Commission rules issued in April 2005, SFAS 123(R) is effective for fiscal years that begin after June 15, 2005 and will be adopted by IPC in the first quarter of 2006. Adoption is not expected to have a material effect on IPC's financial statements.

SFAS 153: In December 2004, the FASB issued SFAS 153, "Exchanges of Nonmonetary Assets," which amends existing guidance on

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accounting for nonmonetary transactions. SFAS 153 is effective for exchanges occurring in fiscal periods beginning after June 15, 2005, and is not expected to have a material effect on IPC's financial statements.

SFAS 154: In May 2005 the FASB issued SFAS 154, "Accounting Changes and Error Corrections - a replacement of APB Opinion No. 20 and FASB Statement No. 3." SFAS 154 changes the requirements for the accounting for and reporting of a change in accounting principle. It applies to all voluntary changes in accounting principle and to changes required by an accounting pronouncement that does not include specific transition provisions. When a pronouncement includes specific transition provisions, those provisions should be followed. SFAS 154 requires retrospective application to prior periods' financial statements of changes in accounting principle, unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. When it is impracticable to determine the period-specific effects of an accounting change on one or more individual prior periods presented, SFAS 154 requires that the new accounting principle be applied to the balances of assets and liabilities as of the beginning of the earliest period for which retrospective application is practicable and that a corresponding adjustment be made to the opening balance of retained earnings for that period rather than being reported in an income statement. When it is impracticable to determine the cumulative effect of applying a change in accounting principle to all prior periods, SFAS 154 requires that the new accounting principle be applied as if it were adopted prospectively from the earliest date practicable. SFAS 154 is effective for accounting changes and corrections of errors made in fiscal years beginning after December 15, 2005.

Other Accounting Policies

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

Reclassifications

Certain items previously reported for years prior to 2005 have been reclassified to conform to the current year's presentation. Net income and shareholder's equity were not affected by these reclassifications.

2. INCOME TAXES:

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

	2005	2004
	(thousands of dollars)	
Federal income tax expense bases on federal statutory rate	\$ 39,861	\$ 25,394
Change in taxes resulting from:		
Equity in earnings of subsidiary companies	(3,106)	(2,867)
AFDC	(2,709)	(2,400)
Investment tax credits	(3,295)	(3,295)
Repair allowance	(1,750)	(2,450)
Removal costs	(1,490)	(1,244)
Pension accrual	1,276	1,237
Capitalized overhead costs	-	(3,658)
Regulatory tax liability	-	(16,457)
Settlement of prior years tax returns	(2)	(1,460)
State income taxes, net of federal benefit	6,847	4,100
Depreciation	5,603	4,350
Other, net	816	697
Total income tax expense (benefit)	\$ 42,051	\$ 1,947
Effective tax rate	36.9%	2.7%

The items comprising income tax expense are as follows:

	2005	2004
	(thousands of dollars)	
Income taxes currently payable:		

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Federal	\$ 65,896	\$ 16,451
State	9,177	7,318
Total	75,073	23,769
Income taxes deferred:		
Federal	(29,891)	(17,318)
State	(5,081)	(3,551)
Total	(34,972)	(20,869)
Investment tax credits:		
Deferred	5,374	2,700
Restored	(3,424)	(3,653)
Total	1,950	(953)
Total income tax expense (benefit)	\$ 42,051	\$ 1,947

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

	2005	2004
	(thousands of dollars)	
Deferred tax assets:		
Regulatory liabilities	\$ 41,627	\$ 40,447
Advances for construction	6,881	5,357
Deferred compensation	13,276	12,324
Emission allowances	27,380	-
Other	14,496	14,584
Total	103,660	72,712
Deferred tax liabilities:		
Property, plant and equipment	240,144	241,324
Regulatory assets	346,116	344,220
Conservation programs	5,705	6,972
PCA	17,410	20,516
Other	666	722
Total	610,041	613,754
Net deferred tax liabilities	\$ 506,381	\$ 541,042

Amounts accrued by IPC for income taxes are payable to IDACORP, as IPC joins in the filing of IDACORP's federal and state consolidated income tax returns.

Capitalized Overhead Costs: On August 2, 2005, the IRS and Treasury Department issued guidance interpreting the meaning of "routine and repetitive" for purposes of the simplified service cost and simplified production methods of the Internal Revenue Code section 263A uniform capitalization rules. The guidance was issued in the form of a revenue ruling (Rev. Rul. 2005-53) and proposed and temporary regulations. The regulations are effective for tax years ending on or after August 2, 2005, and the revenue ruling applies for all prior open years. Both pieces of guidance take a more restrictive view of the definition of self-constructed assets produced by a taxpayer on a "routine and repetitive" basis than do the current treasury regulations.

Generally, section 263A requires the capitalization of all direct costs and those indirect costs, known as "mixed service costs", which directly benefit or are incurred by reason of the production of property by a taxpayer. The treasury regulations for section 263A provide

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several "safe-harbor" methods taxpayers may adopt in order to comply with the statute. The simplified service cost method is one of the methods available for the calculation of indirect overhead ("mixed service costs") cost capitalization. IPC changed to the simplified service cost method for both the self-construction of utility plant and production of electricity beginning with its 2001 federal income tax return.

For IPC, the simplified service cost method produces a current tax deduction for costs capitalized to electricity production that are capitalized into fixed assets for financial accounting purposes. Deferred income tax expense has not been provided for this deduction because the prescribed regulatory tax accounting treatment does not allow for inclusion of such deferred tax expense in current rates. Rate regulated enterprises are required to recognize such adjustments as regulatory assets if it is probable that such amounts will be recovered from customers in future rates.

For fiscal years 2002 through 2004, the simplified service cost method decreased IPC's income tax expense by \$60 million and resulted in cash refunds from federal and state tax authorities of \$75 million. For years 2004 and prior open tax years, if IPC cannot satisfy the new guidance as currently drafted, IPC would be required to use another method of uniform capitalization, which could be more or less favorable to IPC than the simplified service cost method. A less favorable method could result in a one time charge to earnings and reduced cash flow that could be partially offset by carryover tax credits, accelerated tax depreciation, changes in tax regulations and state regulatory recovery.

The temporary regulations are effective for IPC's 2005 tax year and, as drafted, preclude IPC from using this method for self-constructed assets for 2005 and thereafter. Accordingly, in the third quarter of 2005, IPC reversed its previously accrued 2005 tax deduction for capitalized overhead costs for both financial reporting and estimated tax payment purposes. IPC is evaluating alternatives for a new uniform capitalization method.

IPC is actively involved in pursuing resolution of this matter and is working diligently with the IRS in the examination process. At this time, IPC cannot predict the earnings or cash flow impacts that the revenue ruling, temporary regulations, or additional action by the IRS in this matter may have on 2005 or prior tax years.

Regulatory Settlement

In 2004, IPC and the IPUC finalized an income tax issue from IPC's 2003 Idaho general rate case. The issue concerned the regulatory accounting treatment for the capitalized overhead tax method IPC adopted in the 2001 IDACORP federal income tax return. As a result of the settlement, a \$16 million regulatory tax liability was reversed, creating benefit in 2004.

3. COMMON STOCK:

In December 2004, IDACORP contributed \$86 million of additional equity to IPC. No additional shares of IPC common stock were issued in this transaction.

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. On September 20, 2004, IPC redeemed all of its 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.

4. PREFERRED STOCK OF IDAHO POWER COMPANY:

On September 20, 2004, IPC redeemed all of its outstanding preferred stock for \$54 million using proceeds from the issuance of first mortgage bonds. This amount includes \$2 million of premium that was recorded as preferred dividends on the Consolidated Statements of Income. The redemption price was \$104 per share for the 122,989 shares of 4% preferred stock, \$102.97 per share for the 150,000 shares of 7.68% preferred stock and \$103.18 per share for the 250,000 shares of 7.07% preferred stock, plus accumulated and unpaid dividends.

5. LONG-TERM DEBT:

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

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	2005	2004
(thousands of dollars)		
First mortgage bonds:		
5.83 % Series due 2005	\$ -	\$ 60,000
7.38 % Series due 2007	80,000	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	-
Total first mortgage bonds	785,000	785,000
Pollution control revenue bonds:		
Variable Auction Rate Series 2003 due 2024 (a)	49,800	49,800
6.05 % Series 1996A due 2026	68,100	68,100
Variable Rate Series 1996B due 2026	24,200	24,200
Variable Rate Series 1996C due 2026	24,000	24,000
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	11,700	11,700
Unamortized premium/discount - net	(3,325)	(3,135)
Total	983,720	983,910
Current maturities of long-term debt		(60,000)
Total long-term debt	\$ 983,720	\$ 923,910

(a) Humboldt County Pollution Control Revenue bonds are secured by first mortgage bonds, bringing the total of first mortgage bonds outstanding at December 31, 2005 to \$834.8 million.

At December 31, 2005, the maturities for the aggregate amount of long-term debt outstanding were (in thousands of dollars):

	2006	2007	2008	2009	2010	Thereafter
IPC	\$ -	\$ 81,064	\$ 1,064	\$ 81,064	\$ 1,064	\$ 822,789

On October 22, 2003, Humboldt County, Nevada issued, for the benefit of IPC, \$49.8 million Pollution Control Revenue Refunding Bonds (Idaho Power Company Project) Series 2003 due December 1, 2024. IPC borrowed the proceeds from the issuance pursuant to a Loan Agreement with Humboldt County and is responsible for payment of principal, premium, if any, and interest on the bonds. The bonds are secured, as to principal and interest, by IPC first mortgage bonds and as to principal and interest when due, by an insurance policy issued by Ambac Assurance Corporation. The bonds were issued in an auction rate mode under which the interest rate is reset every 35 days. The initial auction rate was set at 0.95 percent. At December 31, 2005, the auction rate was 3.15 percent. Proceeds from this issuance together with other funds provided by IPC were used to redeem the outstanding \$49.8 million Pollution Control Revenue Bonds (Idaho Power Company Project) 8.3% Series 1984 due 2014, on December 1, 2003, at 103 percent.

On March 14, 2003, IPC filed a \$300 million shelf registration statement that could be used for first mortgage bonds (including medium-term notes), unsecured debt and preferred stock. On May 8, 2003, IPC issued \$140 million of secured medium-term notes in two series: \$70 million First Mortgage Bonds 4.25% Series due 2013 and \$70 million First Mortgage Bonds 5.50% Series due 2033. Proceeds were used to pay down IPC short-term borrowings incurred from the payment at maturity of \$80 million First Mortgage Bonds 6.40%

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Series due 2003 and the early redemption of \$80 million First Mortgage Bonds 7.50% Series due 2023, on May 1, 2003. On March 26, 2004, IPC issued \$50 million First Mortgage Bonds 5.50% Series due 2034. Proceeds were used to reduce short-term borrowings and replace short-term investments, which were used on March 15, 2004 to pay at maturity the \$50 million First Mortgage Bonds 8% Series due 2004. On August 16, 2004, IPC issued \$55 million First Mortgage Bonds 5.875% Series due 2034. On September 20, 2004, the proceeds of this issuance were used to redeem all of IPC's outstanding preferred stock.

On January 19, 2005, IPC filed a \$245 million shelf registration statement that could be used for first mortgage bonds (including medium-term notes) and debt securities, and when combined with the \$55 million remaining from the March 14, 2003 shelf registration, provided for \$300 million available in shelf registration form. On August 26, 2005 IPC issued \$60 million First Mortgage Bonds 5.30% Series due 2035. Proceeds were invested in short-term investments, which were used on September 9, 2005 to pay at maturity the \$60 million First Mortgage Bonds 5.83% Series due 2005. At December 31, 2005, \$240 million remained available to be issued on this shelf registration statement.

On August 17, 2004, IPC redeemed all \$1 million of its Rural Electrification Administration notes.

On August 30, 2005, IPC settled a forward-starting interest rate swap agreement by making a payment of \$2.7 million to the counterparty of the agreement. In accordance with regulatory accounting practices under SFAS 71, IPC is amortizing this amount over the life of its 5.30% First Mortgage Bonds due 2035.

At December 31, 2005 and 2004, the overall effective cost of IPC's outstanding debt was 5.84 percent and 5.69 percent, respectively.

The amount of first mortgage bonds issuable by IPC is limited to a maximum of \$1.1 billion and by property, earnings and other provisions of the mortgage and supplemental indentures thereto. IPC may amend the indenture and increase this amount without consent of the holders of the first mortgage bonds. Substantially all of the electric utility plant is subject to the lien of the mortgage. As of December 31, 2005, IPC could issue under the mortgage approximately \$560 million of additional first mortgage bonds based on unfunded property additions and \$452 million of additional first mortgage bonds based on retired first mortgage bonds. At December 31, 2005, unfunded property additions, which consist of electric property, were approximately \$933 million.

6. 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, 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, 2005		December 31, 2004	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
(thousands of dollars)				
Assets:				
Notes receivable	\$ 7,047	\$ 6,876	\$ 8,946	\$ 8,877
Investments	21,137	21,137	53,155	53,155
Liabilities:				
Long-term debt	\$ 987,045	\$ 1,003,651	\$ 987,045	\$ 1,008,369

7. NOTES PAYABLE:

At December 31, 2005, IPC had regulatory authority to incur up to \$250 million of short-term indebtedness. IPC has a \$200 million credit facility that expires on March 31, 2010. Under this facility IPC pays a facility fee on the commitment, quarterly in arrears, based on its

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rating for senior unsecured long-term debt securities without third-party credit enhancement as provided by Moody's and S&P. IPC's commercial paper may be issued up to the amounts supported by the bank credit facilities. There was no commercial paper outstanding at December 31, 2005 or 2004.

8. COMMITMENTS AND CONTINGENCIES:

As of December 31, 2005, IPC had agreements to purchase energy from 87 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 715,209 megawatt-hours (MWh) at a cost of \$43 million in 2005, 677,868 MWh at a cost of \$40 million in 2004 and 654,131 MWh at a cost of \$38 million in 2003.

At December 31, 2005, IPC had the following long-term commitments relating to purchases of energy, capacity, transmission rights and fuel:

(thousands of dollars)	2006	2007	2008	2009	2010	Thereafter
Cogeneration and small power prod	\$59,719	\$70,283	\$70,283	\$73,753	\$73,753	\$1,039,377
Power and transmission rights	148,818	14,362	8,762	6,193	3,714	13,001
Fuel	43,370	40,496	26,997	18,013	12,010	10,118

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, 2005. 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.

From time to time IPC is a party to legal claims, actions and complaints in addition to those discussed below. IPC believes that it has meritorious defenses to all lawsuits and legal proceedings. 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 IPC's evaluation, they believe that the resolution of these matters, taking into account existing reserves, will not have a material adverse effect on IPC's financial position, results of operations or cash flows.

Legal Proceedings

Public Utility District No. 1 of Grays Harbor County, Washington: On October 15, 2002, Public Utility District No. 1 of Grays Harbor County, Washington (Grays Harbor) filed a lawsuit in the Superior Court of the State of Washington, for the County of Grays Harbor, against IDACORP, IPC and IE. On March 9, 2001, Grays Harbor entered into a 20-megawatt (MW) purchase transaction with IPC for the purchase of electric power from October 1, 2001 through March 31, 2002, at a rate of \$249 per MWh. In June 2001, with the consent of Grays Harbor, IPC assigned all of its rights and obligations under the contract to IE. In its lawsuit, Grays Harbor alleged that the assignment was void and unenforceable, and sought restitution from IE and IDACORP, or in the alternative, Grays Harbor alleged that the contract should be rescinded or reformed. Grays Harbor sought as damages an amount equal to the difference between \$249 per MWh and the "fair value" of electric power delivered by IE during the period October 1, 2001 through March 31, 2002.

IDACORP, IPC and IE removed this action from the state court to the U.S. District Court for the Western District of Washington at Tacoma. On November 12, 2002, the companies filed a motion to dismiss Grays Harbor's complaint, asserting that the U.S. District Court lacked jurisdiction because the FERC has exclusive jurisdiction over wholesale power transactions and thus the matter is preempted under the Federal Power Act and barred by the filed-rate doctrine. The court ruled in favor of the companies' motion to dismiss and dismissed the case with prejudice on January 28, 2003. On February 25, 2003, Grays Harbor filed a Notice of Appeal, appealing the final judgment of dismissal to the U.S. Court of Appeals for the Ninth Circuit. On August 10, 2004, the Ninth Circuit affirmed the dismissal of Grays Harbor's complaint, finding that Grays Harbor's claims were preempted by federal law and were barred by the filed-rate doctrine. The court also remanded the case to allow Grays Harbor leave to amend its complaint to seek declaratory relief only as to contract formation, and held that Grays Harbor could seek monetary relief, if at all, only from the FERC, and not from the courts. IDACORP, IPC and IE

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sought rehearing from the Ninth Circuit arguing that the court erred in granting leave to amend the complaint as such a declaratory relief claim would be preempted and would be barred by the filed-rate doctrine. The Ninth Circuit denied the rehearing request on October 25, 2004, and the decision became final on November 12, 2004.

On that same date, the companies took steps to have the case transferred and consolidated with other similar cases arising out of the California energy crisis currently pending before the Honorable Robert H. Whaley, sitting by designation in the Southern District of California and presiding over Multidistrict Litigation Docket No. 1405, regarding California Wholesale Electricity Antitrust Litigation. On November 18, 2004, Grays Harbor filed an amended complaint alleging that the contract was formed under circumstances of "mistake" as to an "artificial . . . power shortage." Grays Harbor asked that the contract therefore be declared "unenforceable" and found "unconscionable." On December 23, 2004, the Judicial Panel on Multidistrict Litigation conditionally transferred the case to Judge Whaley. Grays Harbor sought to vacate the transfer; however, on April 18, 2005, the Judicial Panel on Multidistrict Litigation ordered the case transferred. On May 18, 2005, IDACORP, IPC and IE filed a motion to dismiss the amended complaint. The motion was heard on September 29, 2005.

On December 16, 2005, Judge Whaley issued an Order Setting Status Conference wherein, rather than expressly ruling on the companies' motion to dismiss Grays Harbor's amended complaint, he ruled that either Grays Harbor or the companies may, within 45 days of the date of the order, petition the FERC to weigh in on this case in light of "the extensive hearings . . . already undertaken by FERC in the Northwest refund proceeding" which may be relevant to this case. On January 27, 2006 Grays Harbor and the companies jointly filed a stipulation requesting that the court stay the action and extend the time in which the parties may petition the FERC by sixty days to March 31, 2006 stating that the parties felt the case was appropriate for mediation prior to further proceedings. On January 31, 2006 the court approved the stipulation staying the case until March 31, 2006 and setting a status conference for April 14, 2006. 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.

Port of Seattle: On May 21, 2003, the Port of Seattle, a Washington municipal corporation, filed a lawsuit against 20 energy firms, including IPC and IDACORP, in the U.S. District Court for the Western District of Washington at Seattle. The Port of Seattle's complaint alleges fraud and violations of state and federal antitrust laws and the Racketeer Influenced and Corrupt Organizations Act. On December 4, 2003, the Judicial Panel on Multidistrict Litigation transferred the case to the Southern District of California for inclusion with several similar multidistrict actions currently pending before the Honorable Robert H. Whaley.

All defendants, including IPC and IDACORP, moved to dismiss the complaint in lieu of answering it. The motions were based on the ground that the complaint seeks to set alternative electrical rates, which are exclusively within the jurisdiction of the FERC and are barred by the filed-rate doctrine. A hearing on the motion to dismiss was heard on March 26, 2004. On May 28, 2004, the court granted IPC's and IDACORP's motion to dismiss. In June 2004, the Port of Seattle appealed the court's decision to the U.S. Court of Appeals for the Ninth Circuit. On July 19, 2005 the companies filed a motion for summary affirmance of the district court's order dismissing the Port of Seattle's complaint. The Ninth Circuit issued an order denying this motion on October 17, 2005. The appeal has been fully briefed, and oral argument has been scheduled for March 7, 2006. 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.

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. The companies' motion to dismiss the complaint was granted on February 11, 2005. Wah Chang appealed to the Ninth Circuit on March 10, 2005. The Ninth Circuit set a briefing schedule on the appeal, requiring Wah Chang's opening brief to be filed by July 6, 2005. On May 18, 2005, Wah Chang filed a motion to stay the appeal or in the alternative to voluntarily dismiss the appeal without prejudice to reinstatement. The companies opposed the motion and filed a cross-motion asking the Court to summarily affirm the district court's order of dismissal. On July 8, 2005, the Ninth Circuit denied Wah Chang's motion and also denied the companies' motion for summary affirmance without prejudice to renewal following the filing of Wah Chang's opening brief. Wah Chang's opening brief was filed on September 21, 2005. On October 11, 2005 the companies, along with the other defendants, filed a motion to consolidate this appeal with Wah Chang v. Duke Energy Trading and Marketing currently pending before the Ninth Circuit. On October 18, 2005 the Ninth

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Circuit granted the motion to consolidate and established a revised briefing schedule. The companies filed an answering brief on November 30, 2005. Wah Chang's reply brief was filed on January 6, 2006. The appeal has been fully briefed; however, no date has yet been set for oral argument. 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.

City of Tacoma: On June 7, 2004, the City of Tacoma, Washington filed a lawsuit in the U.S. District Court for the Western District of Washington at Tacoma against numerous defendants including IDACORP, IE and IPC. The City of Tacoma's complaint alleges violations of the Sherman Antitrust Act. The claimed antitrust violations are based on allegations of energy market manipulation, false load scheduling and bid rigging and misrepresentation or withholding of energy supply. The plaintiff seeks compensatory damages of not less than \$175 million.

On September 8, 2004, this case was transferred and consolidated with other similar cases currently pending before the Honorable Robert H. Whaley. The companies' motion to dismiss the complaint was granted on February 11, 2005. The City of Tacoma appealed to the Ninth Circuit on March 10, 2005.

On August 9, 2005, the companies moved for summary affirmance of the district court's order dismissing the City of Tacoma's complaint. The City of Tacoma filed a response to the companies' motion for summary affirmance on August 24, 2005. The Ninth Circuit denied the companies' motion for summary affirmance on November 3, 2005. The appeal has been fully briefed; however, no date has yet been set for oral argument. 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.

Wholesale Electricity Antitrust Cases I & II: These cross-actions against IE and IPC emerged from multiple California state court proceedings first initiated in late 2000 against various power generators/marketers by various California municipalities and citizens. Suit was filed against entities including Reliant Energy Services, Inc., Reliant Ormond Beach, L.L.C., Reliant Energy Etiwanda, L.L.C., Reliant Energy Ellwood, L.L.C., Reliant Energy Mandalay, L.L.C. and Reliant Energy Coolwater, L.L.C. (collectively, Reliant); and Duke Energy Trading and Marketing, L.L.C., Duke Energy Morro Bay, L.L.C., Duke Energy Moss Landing, L.L.C., Duke Energy South Bay, L.L.C. and Duke Energy Oakland, L.L.C. (collectively, Duke). While varying in some particulars, these cases made a common claim that Reliant, Duke and certain others (not including IE or IPC) colluded to influence the price of electricity in the California wholesale electricity market. The plaintiffs asserted various claims that the defendants violated the California Antitrust Law (the Cartwright Act), Business and Professions Code Section 16720 and California's Unfair Competition Law, Business and Professions Code Section 17200. Among the acts complained of are bid rigging, information exchanges, withholding of power and other wrongful acts. These actions were subsequently consolidated, resulting in the filing of Plaintiffs' Master Complaint in San Diego Superior Court on March 8, 2002.

On April 22, 2002, more than a year after the initial complaints were filed, two of the original defendants, Duke and Reliant, filed separate cross-complaints against IPC and IE, and approximately 30 other cross-defendants. Duke and Reliant's cross-complaints sought indemnity from IPC, IE and the other cross-defendants for an unspecified share of any amounts they must pay in the underlying suits because, they allege, other market participants like IPC and IE engaged in the same conduct at issue in the Plaintiffs' Master Complaint. Duke and Reliant also sought declaratory relief as to the respective liability and conduct of each of the cross-defendants in the actions alleged in the Plaintiffs' Master Complaint. Reliant also asserted a claim against IPC for alleged violations of the California Unfair Competition Law, Business and Professions Code Section 17200. As a buyer of electricity in California, Reliant requested the same relief from the cross-defendants, including IPC, as that sought by plaintiffs in the Plaintiffs' Master Complaint as to any power Reliant purchased through the California markets.

Some of the newly added defendants (foreign citizens and federal agencies) removed that litigation to federal court. IPC and IE, together with numerous other defendants added by the cross-complaints, moved to dismiss these claims, and those motions were heard in September 2002, together with motions to remand the case back to state court filed by the original plaintiffs. On December 13, 2002, the U.S. District Court granted Plaintiffs' Motion to Remand to state court, but did not issue a ruling on IPC and IE's motion to dismiss. The U.S. Court of Appeals for the Ninth Circuit granted certain Defendants and Cross-Defendants' Motions to Stay the Remand Order while they appeal the order. The briefing on the appeal was completed in December 2003. On December 8, 2004, the Ninth Circuit issued its opinion in *People of California v. NRG Energy, Inc., et al.*, which affirmed the district court's remand of these cases to state court and dismissed certain federal government defendants due to their sovereign immunity from suit.

On June 3, 2005, the cross-defendants, including IPC and IE, filed a demurrer in state court seeking to dismiss the cross-complaints filed by Duke and Reliant. On August 8, 2005, before that demurrer was to be heard, the Clerk of the Court entered Duke's voluntary dismissal, with prejudice, of the cross-complaint against IE and IPC. Further briefing and hearing on IE and IPC's demurrer to the Reliant

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cross-complaint was stayed pending the outcome of the demurrer filed by Reliant on the Master Complaint. On September 22, 2005, the Court took Reliant's demurrer off calendar pending approval of a proposed settlement as to the plaintiff's Master Complaint. On October 3, 2005 the court sustained the defendants' (other than Reliant's) joint demurrer to the Master Complaint and scheduled a status conference to discuss the status of the cross-complaints. On October 13, 2005 the court set IE and IPC's demurrer on the cross-complaint for hearing on December 23, 2005.

However, on November 14, 2005, Judge Joan M. Lewis approved a stipulation between the cross-defendants, including IE and IPC, and Reliant. This stipulation provided for dismissal of IE and IPC by Reliant with prejudice subject to reinstatement in the event that approval and finalization of a settlement agreement between Reliant and the underlying plaintiffs in these cases does not occur. The December 23, 2005 hearing on IE and IPC's demurrer to the cross-complaint was taken off the calendar. A hearing regarding approval of the Reliant settlement was held on Friday January 6, 2006 before Judge Lewis.

Reliant has filed a request for dismissal of IE and IPC with prejudice, which was entered by the clerk of the court on December 19, 2005. Pursuant to IE and IPC's stipulation with Reliant, the dismissal will become final once any judgment and order from the Court approving the Reliant settlement with the plaintiffs becomes final (i.e., once the time for any appeal on the order approving the settlements runs or, if review is sought, the trial court's approval order is affirmed after resolution of all appeals). The time for an appeal from an order approving the settlements would range from 30 to 90 days after entry of the Court's judgments and orders.

If the Court does not grant final approval for the Reliant settlement, Reliant may elect to reactivate its cross-complaint. Similarly, should the Court for any reason fail to approve the Reliant settlement by May 31, 2006, IE and IPC may withdraw from the stipulation agreement by giving ten days' advance written notice. 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:

California Power Exchange Chargeback:

As a component of IPC's non-utility energy trading in the State of California, IPC, in January 1999, entered into a participation agreement with the California Power Exchange (CalPX), a California non-profit public benefit corporation. The CalPX, at that time, operated a wholesale electricity market in California by acting as a clearinghouse through which electricity was bought and sold. Pursuant to the participation agreement, IPC could sell power to the CalPX under the terms and conditions of the CalPX Tariff. Under the participation agreement, if a participant in the CalPX defaulted on a payment, the other participants were required to pay their allocated share of the default amount to the CalPX. The allocated shares were based upon the level of trading activity, which included both power sales and purchases, of each participant during the preceding three-month period.

On January 18, 2001, the CalPX sent IPC an invoice for \$2 million - a "default share invoice" - as a result of an alleged 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, due on February 20, 2001, as a result of alleged payment defaults by Southern California Edison, Pacific Gas and Electric Company and others. However, because the CalPX owed IPC \$11 million for power sold to the CalPX in November and December 2000, IPC did not pay the February 8 invoice. The CalPX later reversed IPC's payment of the January 18, 2001 invoice, but on June 20, 2001 invoiced IPC for an additional \$2 million which the CalPX has not reversed. The CalPX owes IPC \$14 million for power sold in November and December including \$2 million associated with the default share invoice dated June 20, 2001. IPC essentially discontinued energy trading with the CalPX and the California Independent System Operator (Cal ISO) in December 2000.

IPC believes that the default invoices were not proper and that IPC owes no further amounts to the CalPX. IPC has pursued all available remedies in its efforts to collect amounts owed to it by the CalPX. On February 20, 2001, IPC filed a petition with the FERC to intervene in a proceeding that requested the FERC to suspend the use of the CalPX chargeback methodology and provide for further oversight in the CalPX's implementation of its default mitigation procedures.

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. To the extent that Pacific Gas and Electric Company's bankruptcy filing affects the collectibility of the receivables from the CalPX and the Cal ISO, the receivables from these entities are at greater risk.

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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. Shortly after the issuance of that order, the CalPX segregated the CalPX chargeback amounts it had collected in a separate account. The CalPX claimed it was awaiting further orders from the FERC and the bankruptcy court before distributing the funds that it collected under its chargeback tariff mechanism. 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. On November 8, 2004, IE, along with a number of other parties, sought rehearing of that order. On March 15, 2005, the FERC issued an order on rehearing confirming that the CalPX is to continue to hold the chargeback funds, but solely to offset seller-specific shortfalls in the seller's CalPX account at the conclusion of the California refund proceeding. Balances are to be returned to the respective sellers at the conclusion of a seller's participation in the refund proceeding. Powerex Corp. filed a petition for review of the Commission's order on March 24, 2005 in the D.C. Circuit. Neither a briefing schedule nor a date for oral argument has been set.

Based upon the settlement agreement filed with the FERC on February 17, 2006 between the California Parties and IE and IPC discussed below in "California Refund," the California Parties have agreed to support a request that the FERC authorize the CalPX to release \$2.27 million related to the chargeback proceeding to IE and IPC.

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. Subsequently, 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, and therefore not in compliance with the Federal Power Act. The June 19 order also required all buyers and sellers in the Cal ISO market during the subject time frame to participate in settlement discussions to explore the potential for resolution of these issues without further FERC action. The settlement discussions failed to bring resolution of the refund issue and as a result, the FERC's Chief Administrative Law Judge submitted a Report and Recommendation to the FERC recommending that the FERC adopt the methodology set forth in the report and set for evidentiary hearing an analysis of the Cal ISO's and the CalPX's spot markets to determine what refunds may be due upon application of that methodology.

On July 25, 2001, the FERC issued an order establishing evidentiary hearing procedures related to the scope and methodology for calculating 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).

The Administrative Law Judge issued a Certification of Proposed Findings on California Refund Liability on December 12, 2002.

The FERC issued its Order on Proposed Findings on Refund Liability on March 26, 2003. In large part, the FERC affirmed the recommendations of its Administrative Law Judge. However, the FERC changed a component of the formula the Administrative Law Judge was to apply when it adopted findings of its staff that published California spot market prices for gas did not reliably reflect the prices a gas market, that had not been manipulated, would have produced, despite the fact that many gas buyers paid those amounts. The findings of the Administrative Law Judge, as adjusted by the FERC's March 26, 2003 order, are expected to increase the offsets to amounts still owed by the Cal ISO and the CalPX to the companies. Calculations remain uncertain because (1) the FERC has required the Cal ISO to correct a number of defects in its calculations, (2) it is unclear what, if any, effect the ruling of the Ninth Circuit in *Bonneville Power Administration v. FERC*, described below, might have on the ISO's calculations, and (3) the FERC has stated that if refunds will prevent a seller from recovering its California portfolio costs during the Refund Period, it will provide an opportunity for a cost showing by such a respondent. On August 8, 2005, the FERC issued an Order establishing the framework for filings by sellers who elected to make such a cost showing. On September 14, 2005 IE and IPC made a joint cost filing, as did approximately thirty other sellers. On October 11, 2005, the California entities filed comments on the companies' cost filing and those made by other parties. IPC and IE submitted reply comments on October 19, 2005. The California entities filed supplemental comments on October 24, 2005 and IPC and IE filed supplemental reply comments on October 27, 2005. IPC and IE are unsure of the impact the FERC's rulings will have on the refunds due from California. However, as to potential refunds, if any, IPC and IE believe their exposure is likely to be offset by amounts due from California entities.

In December of 2005, IE and IPC reached a tentative agreement with the California Parties settling matters encompassed by the California Refund proceeding including IE and IPC's cost filing and refund obligation. On January 20, 2006, the Parties filed a request with the FERC asking that the FERC defer ruling on IE and IPC's cost filing for thirty days so the parties could complete and file the settlement agreement with the FERC. On January 26, 2006, the FERC granted the requested deferral and required that the settlement be filed by

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February 17, 2006. On February 17, 2006, IE and IPC jointly filed with the California Parties (Pacific Gas & Electric Company, San Diego Gas & Electric Company, Southern California Edison, the California Public Utilities Commission, the California Electricity Oversight Board, the California Department of Water Resources and the California Attorney General) an Offer of Settlement at the FERC. Final comments on the settlement are due to be filed by March 20, 2006, after which the FERC will determine whether to approve the settlement. If the settlement is approved by the FERC, IE and IPC will assign \$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 which 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. Approximately \$10.25 million of the remaining IE and IPC receivables are to be released to IE and IPC. In the fourth quarter of 2005 IE reduced by \$9.5 million to \$32 million its reserve against these receivables.

IE, along with a number of other parties, filed an application with the FERC on April 25, 2003 seeking rehearing of the March 26, 2003 order. On October 16, 2003, the FERC issued two orders denying rehearing of most contentions that had been advanced and directing the Cal ISO to prepare its compliance filing calculating revised Mitigated Market Clearing Prices and refund amounts within five months. The Cal ISO has since, on a number of occasions, requested additional time to complete its compliance filings. This Cal ISO compliance filing has been delayed until at least March 2006. The Cal ISO is required to update the FERC on its progress monthly.

On December 2, 2003, IE petitioned the U.S. Court of Appeals for the Ninth Circuit for review of the FERC's orders, and since that time, dozens of other petitions for review have been filed. 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 100. 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. Certain parties also sought further rehearing and clarification before the FERC. On September 21, 2004, the Ninth Circuit convened case management proceedings, a procedure reserved to help organize complex cases. On October 22, 2004, the Ninth Circuit severed a subset of the stayed appeals in order 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 Federal Power Act; (2) the temporal scope of refunds under section 206 of the Federal Power Act; and (3) which categories of transactions are subject to refunds. Oral argument was held on April 12-13, 2005. On September 6, 2005 the Ninth Circuit issued its decision in one of the severed cases, *Bonneville Power Administration v. FERC*. In that decision, the Ninth Circuit concluded that the FERC lacked refund authority over wholesale electric energy sales made by governmental entities and non-public utilities. The time for requests for rehearing was to expire on October 21, 2005, but has been extended until 45 days after the Ninth Circuit issues its decision in the other severed cases. The companies cannot predict whether rehearing will be sought and, if sought, whether it will be granted or what action the FERC might take if the matter is remanded.

On May 12, 2004, the FERC issued an order clarifying portions of its earlier refund orders and, among other things, denying a proposal made by Duke Energy North America and Duke Energy Trading and Marketing (and supported by IE) to lodge as evidence a contested settlement in a separate complaint proceeding, *California Public Utilities Commission (CPUC) v. El Paso, et al.* The CPUC's complaint alleged that the El Paso companies manipulated California energy markets by withholding pipeline transportation capacity into California in order to drive up natural gas prices immediately before and during the California energy crisis in 2000-2001. The settlement will result in the payment by El Paso of approximately \$1.69 billion. Duke claimed that the relief afforded by the settlement was duplicative of the remedies imposed by the FERC in its March 26, 2003 order changing the gas cost component of its refund calculation methodology. IE, along with other parties, has sought rehearing of the May 12, 2004 order. On November 23, 2004, the FERC denied rehearing and within the statutory time allowed for petitions, a number of parties, including IE, filed petitions for review of the FERC's order with the Ninth Circuit. These petitions have since been consolidated with the larger number of review petitions in connection with the California refund proceeding.

In June 2001, IPC transferred its non-utility wholesale electricity marketing operations to IE. Effective with this transfer, the outstanding receivables and payables with the CalPX and the Cal ISO were assigned from IPC to IE. At December 31, 2005, with respect to the CalPX chargeback and the California refund proceedings discussed above, the CalPX and the Cal ISO owed \$14 million and \$30 million, respectively, for energy sales made to them by IPC in November and December 2000. IE has accrued a reserve of \$32 million against these receivables. This reserve was calculated taking into account the uncertainty of collection given the California energy situation. Based on the reserve recorded as of December 31, 2005, IDACORP believes that the future collectibility of these receivables or any potential refunds ordered by the FERC would not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

On March 20, 2002, the California Attorney General filed a complaint with the FERC against various sellers in the wholesale power market,

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including IE and IPC, alleging that the FERC's market-based rate requirements violate the Federal Power Act, and, even if the market-based rate requirements are valid, that the quarterly transaction reports filed by sellers do not contain the transaction-specific information mandated by the Federal Power Act and the FERC. The complaint stated that refunds for amounts charged between market-based rates and cost-based rates should be ordered. The FERC denied the challenge to market-based rates and refused to order refunds, but did require sellers, including IE and IPC, to refile their quarterly reports to include transaction-specific data. The Attorney General appealed the FERC's decision to the U.S. Court of Appeals for the Ninth Circuit. The Attorney General contends that the failure of all market-based rate authority sellers of power to have rates on file with the FERC in advance of sales is impermissible. The Ninth Circuit issued its decision on September 9, 2004, concluding that market-based tariffs are permissible under the Federal Power Act, but remanded the matter 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 that the FERC relies on to confirm the justness and reasonableness of rates charged. Certain parties to the litigation have sought rehearing. The companies cannot predict whether rehearing will be granted or what action the FERC might take if the matter is remanded.

On May 26, 2005 the California Parties filed a motion to lodge additional evidence, primarily audiotapes produced by Enron employees, in the California Refund Proceedings in Docket No. EL00-95. A number of parties, including IDACORP, answered in opposition to that motion.

Market Manipulation:

In a November 20, 2002 order, the FERC permitted discovery and the submission of evidence respecting market manipulation by various sellers during the western power crises of 2000 and 2001.

On March 3, 2003, the California Parties (certain investor owned utilities, the California Attorney General, the California Electricity Oversight Board and the CPUC) filed voluminous documentation asserting 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. Although the contentions of the California Parties were contained in more than 11 compact discs of data and testimony, approximately 12,000 pages, 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.

The California Parties urged the FERC to apply the precepts of its earlier decision, to replace actual prices charged in every hour starting May 1, 2000 through the beginning of the existing Refund Period with a Mitigated Market Clearing Price, seeking approximately \$8 billion in refunds to the Cal ISO and the CalPX. On March 20, 2003, numerous parties, including IE and IPC, submitted briefs and responsive testimony.

In its March 26, 2003 order, discussed above in "California Refund," 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. The Cal ISO was ordered to provide data on each entity's trading practices within 21 days of the order, and each entity was to respond explaining their trading practices within 45 days of receipt of the Cal ISO data. IPC submitted its responses to the show cause orders on September 2 and 4, 2003. On October 16, 2003, IPC reached agreement with the FERC Staff on the two orders commonly referred to as the "gaming" and "partnership" show cause orders. Regarding the gaming order, the FERC Staff determined it had no basis to proceed with allegations of false imports and paper trading 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. With respect to the "partnership" order, the FERC Staff submitted a motion to the FERC to dismiss the proceeding because materials submitted by IPC demonstrated that IPC did not use its "parking" and "lending" arrangement with Public Service Company of New Mexico to engage in "gaming" or anomalous market behavior ("partnership"). The "gaming" settlement was approved by the FERC on March 3, 2004. Eight parties have requested rehearing of the FERC's March 3, 2004 order, but the FERC has not yet acted on those requests. 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. Some of the California Parties and other parties have petitioned the U.S. Court of Appeals for the Ninth Circuit and the District of Columbia Circuit for review of the FERC's orders initiating the show cause proceedings. Some of the parties contend that the scope of the proceedings initiated by the FERC was too narrow. Other parties contend that the orders initiating the show cause proceedings were impermissible. Under the rules for multidistrict litigation, a lottery was held and although these

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cases were to be considered in the District of Columbia Circuit by order of February 10, 2005, the District of Columbia Circuit transferred the proceedings to the Ninth Circuit. The FERC had moved the District of Columbia Circuit to dismiss these petitions on the grounds of prematurity and lack of ripeness and finality. The transfer order was issued before a ruling from the District of Columbia Circuit and the motions, if renewed, will be considered by the Ninth Circuit. IPC is not able to predict 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 CPUC, 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.

The February 17, 2006 Offer of Settlement, if approved by the FERC, would terminate the investigations the FERC initiated without finding of wrongdoing by IE or IPC, and would provide for the disposition of the "gaming" settlement.

Pacific Northwest Refund:

On July 25, 2001, the FERC issued an order establishing another proceeding to explore 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. The FERC Administrative Law Judge submitted recommendations and findings to the FERC on September 24, 2001. The Administrative Law Judge found 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 no refunds should be allowed. Procedurally, the Administrative Law Judge's decision is a recommendation to the commissioners of the FERC. Multiple parties submitted comments to the FERC with respect to the Administrative Law Judge's recommendations. The Administrative Law Judge's recommended findings had been pending before the FERC, when at the request of the City of Tacoma and the Port of Seattle 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 Enron and others. As was the case in the California refund proceeding, at the conclusion of the discovery period, parties alleging market manipulation were to submit their claims to the FERC and responses were due on March 20, 2003. Grays Harbor, whose civil litigation claims were dismissed, as noted above, intervened in this FERC proceeding, asserting on March 3, 2003 that its six-month forward contract, for which performance had been completed, should be treated as a spot market contract for purposes of the FERC's consideration of refunds and is requesting 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. Although the majority of these claims are generic, they named a number of power market suppliers, including IPC and IE, as having used parking services provided by other parties under FERC-approved tariffs and thus as being candidates for claims of improperly having received congestion revenues from the Cal ISO. On June 25, 2003, after having considered oral argument held earlier in the month, the FERC issued its Order Granting Rehearing, Denying Request to Withdraw Complaint and Terminating Proceeding, in which it 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 CPUC and Puget Sound Energy, Inc. filed petitions for review in the Ninth Circuit. These petitions have been consolidated. Grays Harbor did not file a petition for review, although it has sought to intervene in the proceedings initiated by the petitions of others. On July 21, 2004, the City of Seattle submitted to the Ninth Circuit in the Pacific Northwest refund petition for review a motion requesting leave to offer additional evidence before the FERC in order to try to secure another opportunity for reconsideration by the FERC of its earlier rulings. The evidence that the City of Seattle seeks to introduce before the FERC consisted of audio tapes of what purports to be Enron trader conversations containing inflammatory language that have been the subject of coverage in the press. Under Section 313(b) of the Federal Power Act, a court is empowered to direct the introduction of additional evidence if it is material and could not have been introduced during the underlying proceeding. On September 29, 2004, the Ninth Circuit denied the City of Seattle's motion for leave to adduce evidence, without prejudice

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to renewing the request for remand in the briefing in the Pacific Northwest refund case. Briefing was completed on May 25, 2005; however, no date has been set for oral argument.

The companies are unable to predict the outcome of these matters.

9. STOCK-BASED COMPENSATION:

IDACORP has two employee stock-based compensation plans, 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 its long-term growth. IDACORP also has one non-employee stock-based compensation plan, the Director Stock Plan (DSP). The purpose of the DSP is to increase directors' stock ownership through stock-based director 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, 2005, the maximum number of shares available under the LTICP and RSP were 1,552,802 and 74,839, respectively.

All options granted have an exercise price equal to the market price of IDACORP's stock on the date of grant. In accordance with APB 25, no compensation costs have been recognized for the option awards.

IDACORP stock option transactions for shares granted to IPC employees are summarized as follows:

	2005		2004	
	Number of shares	Weighted average exercise price	Number of shares	Weighted average exercise price
Outstanding, beginning of year	952,600	\$ 32.38	886,800	\$ 32.48
Granted	157,837	29.75	110,500	31.21
Exercised	-	-	(4,200)	22.92
Forfeited	(16,300)	30.27	(40,500)	32.27
Outstanding, end of year	1,094,137	\$ 32.03	952,600	\$ 32.38
Exercisable	559,140	\$ 34.41	373,600	\$ 35.42

The following table summarizes information about stock options outstanding at December 31, 2005:

Outstanding			
Exercise Price Ranges	Number of shares	Weighted average exercise price	Weighted average remaining contractual life
\$22.92 - \$31.21	746,514	\$ 26.65	7.93 years
\$35.81 - \$40.31	675,400	38.41	5.37 years
IPC Employees			
\$22.92 - \$31.21	575,537	\$ 26.27	7.87 years
\$35.81 - \$40.31	518,600	\$ 38.43	5.28 years

The fair value of each option granted was estimated at the date of grant using a binomial option-pricing model with the following assumptions:

	2005	2004
Dividend yield	4.07%	3.87%
Expected stock price volatility	23%	29%
Risk-free interest rate	4.22%	3.96%

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Expected option lives	7 years	7 years
Weighted average fair value of options granted	\$5.86	\$7.84

Restricted stock grants have vesting periods up to four years. Performance share grants have a three-year vesting period with the final award amount dependent on the attainment of cumulative EPS performance goals.

Restricted stock and performance share awards are compensatory awards and IPC accrues compensation expense, which is charged to operations, based upon the market value of the granted shares. For 2005 and 2004 total compensation accrued under the plans was less than \$1 million annually.

IDACORP restricted stock and performance shares granted to IPC employees are summarized as follows: (These amounts are included in the table above.)

IPC	2005	2004
Shares outstanding - beginning of year	121,420	80,454
Shares granted	87,620	67,056
Shares forfeited	(25,220)	(24,014)
Shares issued	(251)	(2,076)
Shares outstanding - end of year	183,569	121,420
Weighted average fair value of current year stock grants on grant date	\$ 29.75	\$ 31.15

10. BENEFIT PLANS:

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 2005 and 2004 and does not expect to make a contribution in 2006. The market-related value of assets for the plan is equal to market value.

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.

IPC uses a December 31 measurement date for its plans.

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

	Pension Plan		Deferred Compensation Plan	
	2005	2004	2005	2004
(thousands of dollars)				
Change in benefit obligation:				
Benefit obligation at January 1	\$ 374,333	\$ 339,121	\$ 38,645	\$ 38,870
Service cost	13,129	11,809	1,170	1,358
Interest cost	21,126	20,437	2,151	2,312
Actuarial loss (gain)	11,399	16,626	2,799	(1,225)
Benefits paid	(13,938)	(13,660)	(2,312)	(2,670)
Plan amendments	-	-	270	-
Benefit obligation at December 31	406,049	374,333	42,723	38,645
Change in plan assets:				
Fair value at January 1	356,217	335,229	-	-

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Actual return on plan assets	25,774	34,648	-	-
Employer contributions	-	-	-	-
Benefit payments	(13,938)	(13,660)	-	-
Fair value at December 31	368,053	356,217	-	-
Funded status	(37,996)	(18,116)	(42,723)	(38,645)
Unrecognized actuarial loss	43,806	28,491	13,553	11,443
Unrecognized prior service cost	5,118	5,889	1,414	1,372
Unrecognized net transition liability	-	(126)	-	310
Net amount recognized	\$ 10,928	\$ 16,138	\$ (27,756)	\$ (25,520)
Amounts recognized in the statement of financial position consist of:				
Prepaid (accrued) pension cost	\$ 10,928	\$ 16,138	\$ (39,268)	\$ (36,110)
Intangible asset	-	-	1,414	1,682
Accumulated other comprehensive income	-	-	10,098	8,908
Net amount recognized	\$ 10,928	\$ 16,138	\$ (27,756)	\$ (25,520)
Accumulated benefit obligation	\$ 340,007	\$ 316,498	\$ 39,268	\$ 36,110

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

	Pension Plan		Deferred Compensation Plan	
	2005	2004	2005	2004
(thousands of dollars)				
Service cost	\$ 13,129	\$ 11,809	\$ 1,170	\$ 1,358
Interest cost	21,126	20,437	2,151	2,312
Expected return on assets	(29,690)	(27,935)	-	-
Recognized net actuarial loss	-	-	689	878
Amortization of prior service cost	771	770	228	(361)
Amortization of transition asset	(126)	(263)	310	613
Net periodic pension cost	\$ 5,210	\$ 4,818	\$ 4,548	\$ 4,800

Changes in the Deferred Compensation Plan minimum liability decreased other comprehensive income by \$1 million in 2005, increased other comprehensive income by \$1 million in 2004.

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

	2006	2007	2008	2009	2010	2011-2015
Pension Plan	\$ 14,277	\$ 14,885	\$ 15,988	\$ 17,233	\$ 18,701	\$ 120,589
Deferred Compensation Plan	\$ 2,165	\$ 2,233	\$ 2,629	\$ 2,911	\$ 3,092	\$ 16,653

Plan Asset Allocations: IPC's pension plan and postretirement benefit plan weighted average asset allocations at December 31, 2005 and 2004, by asset category are as follows:

Asset Category	Pension Plan		Postretirement Benefits	
	2005	2004	2005	2004
Equity securities	66%	69%	-%	-%
Debt securities	21	21	-	3
Real estate	10	9	-	-
Other (a)	3	1	100	97
Total	100%	100%	100%	100%

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(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	7%	Short-Term Bonds	10%
Small-Cap Value Stocks	7%	Core Real Estate	9%
Cash and Cash Equivalents	3%	Venture Capital	1%

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 US Treasury Notes. This historical risk premium is then added to the current yield on 10-year US 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. Effective January 1, 2003, IPC amended its postretirement benefit plan. The amendment affects all employees who retire after December 31, 2002, limiting their postretirement benefit to a fixed amount. This amendment 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):

	2005	2004
Service cost	\$ 1,392	\$ 1,400
Interest cost	3,381	3,974
Expected return on plan assets	(2,486)	(2,294)

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Amortization of unrecognized transition obligation	2,040	2,040
Amortization of prior service cost	(535)	(523)
Recognized actuarial loss	754	1,489
Net periodic postretirement benefit cost	\$ 4,546	\$ 6,086

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

	2005	2004
Change in accumulated benefit obligation:		
Benefit obligation at January 1	\$ 71,105	\$ 67,090
Service cost	1,392	1,400
Interest cost	3,381	3,974
Actuarial (gain) loss	(9,186)	2,201
Benefits paid	(2,934)	(3,997)
Plan Amendments	(125)	437
Benefit obligation at December 31	63,633	71,105
Change in plan assets:		
Fair value of plan assets at January 1	29,723	26,603
Actual return on plan assets	1,127	2,301
Employer contributions	800	4,577
Benefits paid	(1,757)	(3,758)
Fair value of plan assets at December 31	29,893	29,723
Funded status	(33,740)	(41,382)
Unrecognized prior service cost	(3,677)	(4,087)
Unrecognized actuarial loss	15,978	24,559
Unrecognized transition obligation	14,280	16,320
Accrued benefit obligations included with other deferred credits	\$ (7,159)	\$ (4,590)

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 measures of accumulated postretirement benefit obligation at December 31, 2004 and net periodic benefit cost for the years ended December 31, 2004 and 2003, do not reflect any amount associated with the subsidy, because IDACORP and IPC initially determined that the effect of the Medicare Act would not be material. Regulations published on January 28, 2005 provided more flexibility in determining actuarial equivalence to Medicare of the benefits provided by the plan than was initially estimated by IDACORP's and IPC's actuaries. Based on these new regulations, the effect of the Medicare Act is a reduction for IDACORP and IPC of \$6 million to the accumulated postretirement benefit obligation at December 31, 2005 and \$1 million to the 2005 periodic postretirement benefit cost.

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):

	2006	2007	2008	2009	2010	2001-2015
Expected benefit payments*	\$ 4,000	\$ 4,200	\$ 4,300	\$ 4,400	\$ 4,600	\$ 25,100
Expected Medicare Part D subsidy receipts	\$ 480	\$ 488	\$ 503	\$ 518	\$ 530	\$ 2,936

*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 2005 and

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2004. 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	\$ 242	\$ (184)
Effect on accumulated postretirement benefit obligation	\$ 2,397	\$ (1,900)

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	
	2005	2004	2005	2004
Discount rate	5.6%	5.75%	5.6%	5.75%
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%
Expected working lifetime (years)	-	-	11	11

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

	Pension Benefits		Postretirement Benefits	
	2005	2004	2005	2004
Discount rate	5.75%	6.15%	5.75%	6.15%
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%
Expected working lifetime (years)	-	-	11	11

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 \$4 million in 2005 and \$3 million in 2004.

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. In accordance with an IPUC order, the portion of the liability attributable to regulated activities in Idaho as of December 31, 1993, was deferred as a regulatory asset, and amortized over a ten-year period, which ended in January 2005.

The following table summarizes postemployment benefit amounts included in IPC's consolidated balance sheets at December 31 (in thousands of dollars):

	2005	2004
Included with regulatory assets	\$ -	\$ 31
Included with other deferred credits	\$ 3,845	\$ 3,924

11. 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 2005 and 2004 (in thousands of dollars):

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	2005		2004	
	Balance	Avg Rate	Balance	Avg Rate
Production	\$ 1,563,008	2.54%	\$ 1,482,517	2.51%
Transmission	580,382	2.19	560,303	2.18
Distribution	1,046,880	2.62	992,248	2.59
General and Other	286,797	8.94	289,748	10.02
Total in service	3,477,067	2.91%	3,324,816	2.96%
Accumulated provision for depreciation	(1,364,640)		(1,316,125)	
In service - net	\$ 2,112,427		\$ 2,008,691	

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, 2005 (in thousands of dollars):

Name of Plant	Location	Utility Plant In Service	Construction Work in Progress	Accumulated Provision for Depreciation	%	MW
Jim Bridger Units 1-4	Rock Springs, WY	\$ 462,240	\$ 5,148	\$ 265,641	33	707
Boardman	Boardman, OR	69,385	454	46,160	10	59
Valmy Units 1 and 2	Winnemucca, NV	311,993	4,042	193,920	50	261

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. Coal purchased by IPC from the joint venture amounted to \$43 million and \$47 million in 2005 and 2004, respectively.

IPC has contracts to purchase the energy from four PURPA Qualified Facilities that are 50 percent owned by Ida-West. Power purchased from these facilities amounted to \$7 million annually in 2005 and 2004.

12. REGULATORY MATTERS:

Idaho General Rate Case

IPC filed a general rate case in October 2005, requesting the IPUC to approve an annual increase to its Idaho retail base rates of \$44 million or 7.8 percent. Base rates primarily reflect IPC's cost of providing electrical service to its customers, including equipment, vehicles and infrastructure.

On February 27, 2006, IPC, the IPUC staff and representatives of customer groups filed a proposed stipulation with the IPUC that, if approved, would settle this case. The stipulation calls for an \$18.1 million increase, or 3.2 percent in IPC's annual electric rates. If approved by the IPUC, the changes in rates are expected to become effective on June 1, 2006.

The rate case filing was made with six months of actual operating expenses and six months of projected expenses. The agreed to increase in rates was lower than the requested amount primarily due to three factors: (1) 2005 actual numbers were significantly less than those forecasted; (2) the overall rate of return agreed to was 8.1 percent compared to the 8.42 percent IPC requested (no specific return on equity was determined); and (3) net power supply costs were kept at levels currently existing in rates. As a result of the settlement, IPC's overall rate of return will increase from the 7.85 percent currently authorized.

Oregon Rate Case

On September 21, 2004, IPC filed an application with the Oregon Public Utility Commission (OPUC) to increase general rates an average of 17.5 percent or approximately \$4.4 million annually.

The OPUC issued its order on July 29, 2005 authorizing an increase of \$0.6 million in annual revenues, an average of 2.37 percent. The significant decrease from IPC's requested amount was primarily related to differences in net power supply costs, which reduced IPC's initial rate request of \$4.4 million by \$2.4 million.

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On September 26, 2005, IPC filed a complaint with the Circuit Court of Marion County, Oregon asking the court to reverse the portion of the OPUC's general rate case order related to the determination of net power supply costs.

Deferred Power Supply Costs

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

	2005	2004
Idaho PCA current year:		
Deferral for the 2005-2006 rate year	\$ -	\$ 22,778
Deferral for the 2006-2007 rate year	3,684	-
Irrigation Lost Revenues	-	13,290
Idaho PCA true-up awaiting recovery:		
Authorized May 2004	-	11,415
Authorized May 2005*	28,567	-
Oregon deferral:		
2001 costs	8,411	12,047
2005 costs	2,880	-
Total deferral	\$ 43,542	\$ 59,530

*\$28 million will be recovered with interest during the 2006-2007 PCA rate year.

Idaho: IPC has a 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 portions, is then included in the calculation of the next year's PCA.

On April 15, 2005, IPC filed the 2005-2006 PCA with the IPUC with a proposed effective date of June 1, 2005. The application proposed to hold the PCA component of customers' rates at the existing level, which is currently recovering \$71 million above base rates. By IPUC order, the 2005 - 2006 PCA includes \$12 million in lost revenues and \$2 million in related interest resulting from IPC's Irrigation Load Reduction Program that was in place in 2001. IPC proposed to defer recovery of approximately \$28 million of power supply costs, or 4.75 percent, for one year to help mitigate the impacts of the increases for the Bennett Mountain Power Plant and the rate case tax settlement adjustments, since all three were proposed to be effective June 1, 2005. The \$28 million will be recovered during the 2006-2007 PCA rate year, and IPC will earn a two percent carrying charge on this balance. The IPUC accepted the company's PCA proposal.

On April 15, 2004, IPC filed its 2004-2005 PCA with the IPUC requesting recovery of \$71 million above base rates and a proposed effective date of June 1, 2004. On May 25, 2004, the IPUC issued Order No. 29506 approving IPC's filing.

On May 15, 2003, the IPUC issued Order No. 29243 approving IPC's 2003-2004 PCA filing, with a small adjustment to the original filing. As approved, IPC's rates were adjusted to collect \$81 million above 1993 base rates.

On April 15, 2002, the IPUC issued Order No. 28992 disallowing recovery of \$12 million of lost revenues resulting from the Irrigation Load Reduction Program that was in place in 2001. IPC believed that this IPUC order was inconsistent with Order No. 28699, dated May 25, 2001, that allowed recovery of such costs, and IPC filed a Petition for Reconsideration on May 2, 2002. On August 29, 2002, the IPUC issued Order No. 29103 denying the Petition for Reconsideration. As a result of this order, approximately \$12 million was expensed in September 2002. IPC believed it was entitled to recover this amount and argued its position before the Idaho Supreme Court on December 5, 2003. On March 30, 2004, the Idaho Supreme Court set aside the IPUC denial of the recovery of lost revenues and remanded the matter to the IPUC to determine the amount of lost revenues to be recovered. On December 29, 2004, the IPUC issued Order No. 29669 allowing IPC to recover \$12 million in lost revenues and \$2 million in interest. The recovery was included as part of IPC's annual PCA beginning June 1, 2005.

Oregon: On March 2, 2005 IPC filed for an accounting order to defer net power supply costs for the period of March 1, 2005 through February 28, 2006 in anticipation of continued low water conditions. The forecasted net system power supply costs included in this filing was \$169 million, of which \$3 million related to the Oregon jurisdiction. IPC is proposing to use the same methodology for this deferral

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filing that was accepted in 2002 for Oregon's share of IPC's 2001 net power supply expenses. On July 1, 2005, IPC, the OPUC staff and the Citizen's Utility Board entered into a stipulation requesting that the OPUC accept IPC's proposed methodology. Under this methodology, IPC will earn its Oregon authorized rate of return on the deferred balance and will recover the amount through rates in future years, as approved by the OPUC.

IPC is also recovering calendar year 2001 excess power supply costs applicable to the Oregon jurisdiction. In two separate 2001 orders, the OPUC approved rate increases totaling six percent, which was the maximum annual rate of recovery allowed under Oregon state law at that time. These increases were recovering approximately \$2 million annually. During the 2003 Oregon legislative session, the maximum annual rate of recovery was raised to ten percent under certain circumstances. IPC requested and received authority to increase the surcharge to ten percent. As a result of the increased recovery rate, which became effective on April 9, 2004, IPC is recovering approximately \$3 million annually.

Fixed-Cost Adjustment Mechanism:

On January 27, 2006, IPC filed with the IPUC for authority to implement a rate adjustment mechanism which would adjust IPC's rates upward or downward to recover IPC's fixed costs independent from the volume of IPC's energy sales. The filing is a continuation of an Idaho case opened in 2004 to investigate the financial disincentives to investment in energy efficiency by IPC. The true-up mechanism, entitled "fixed-cost adjustment" (FCA) would be applicable only to residential service and small general service customers.

The fixed-cost recovery portion of IPC's revenue requirement allowed for recovery in rates would be established for these two customer classes at the time of a general rate case. Thereafter, the FCA would provide a mechanism to true-up the collection of fixed costs to recover the difference between the fixed costs actually recovered through rates and the fixed costs that were allowed to be recovered. Accounting for the FCA would be effective as of January 1, 2006, and the first FCA rate change would occur on June 1, 2007.

The FCA is proposed to change rates coincidentally with IPC's Power Cost Adjustment (PCA) and IPC's seasonal rates. Although the FCA would be timed to adjust on the same schedule as the PCA, the accounting for the FCA would be separate from the PCA. Additionally, IPC proposes to include a three percent cap on any FCA filing, to be applied at the discretion of the IPUC.

Regulatory Assets and Liabilities

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

As of December 31, 2005						As of December 31, 2004
Description	Remaining Amortization Period	Earning a Return	Not Earning a Return	Pending Regulator y Treatment	2005 Total	Total
Regulatory Assets:						
Income Taxes		\$ -	\$ 346,117	\$ -	346,117	\$ 344,220
Conservation	2010	14,592	-	-	14,592	17,836
PCA Deferral	2007	32,251	-	-	32,251	34,193
Oregon Deferral(1)		11,291	-	-	11,291	12,047
Asset Retirement Obligations		-	8,363	-	8,363	8,372
Tax Settlement Order	2006	4,994	-	-	4,994	7,119
Irrigation Lost Revenues (2)	2007	-	-	-	-	13,290
Incremental Security Costs	2008	575	-	-	575	813
Other	Various thru 2007	41	17	-	58	891
Total		\$ 63,744	\$ 354,497	\$ -	\$ 418,241	\$ 438,781

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NOTES TO FINANCIAL STATEMENTS (Continued)			

Regulatory Liabilities:

Income Taxes		\$ -	\$ 41,627	\$ -	\$ 41,627	\$ 40,447
Conservation	2007	6,535	-	-	6,535	5,205
Asset Retirement						
Obligations			152,683	-	152,683	147,700
Deferred ITC			68,786	-	68,786	66,836
IPUC Settlement						
Order	2006	4,021	-	-	4,021	13,671
BPA Settlement	2006	1,393	-	-	1,393	1,833
OPUC Settlement						100
Emission						
Allowance				70,034	70,034	-
Other	Various					
	thru 2007	30	-	-	30	62
Total		\$ 11,979	\$ 263,096	\$ 70,034	\$ 345,109	\$ 275,854

- (1) Capped at 10 percent increase per year.
(2) Included in PCA amortization balance.

For further information on the asset retirement obligations amounts, see Note 14.

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.

13. INVESTMENTS:

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

	2005	2004
IPC Investments:		
Auction rate securities (available-for-sale)	\$ -	\$ 31,650
Equity method investment	38,764	25,028
Available-for-sale equity securities	21,137	21,505
Executive deferred compensation	6,201	6,002
Other investments	1,025	808
Total IPC investments	67,127	84,993

Equity Method Investments

IPC, through its subsidiary Idaho Energy Resources Co. (IERCO), is a 33 percent owner of Bridger Coal Company, which supplies coal to the Jim Bridger generating plant owned in part by IPC.

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

	2005	2004
IERCO	\$ 8,874	\$ 8,190

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

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NOTES TO FINANCIAL STATEMENTS (Continued)			

securities are included in other comprehensive income.

IPC held \$32 million of auction rate securities at December 31, 2004. Auction rate securities are long-term instruments whose interest rates or dividends are reset at specific frequencies. The typical reset periods are either 28 or 35 days. The rates or dividends are reset via a Dutch auction. The original maturities of these securities at the time of issuance ranged from 2007 to 2042. IPC did not hold any auction rate securities at December 31, 2005.

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

	2005			2004		
	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
Available-for-sale securities	\$ 2,925	\$ 497	\$ 21,137	\$ 2,530	\$ 256	\$ 53,155

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

	2005	2004
Proceeds from sales	\$ 120,026	\$ 266,331
Gross realized gains from sales	2,850	2,044
Gross realized losses from sales	643	634

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. This decline is included in other income in the Consolidated Statements of Income. In 2005 and 2004, there were no other-than-temporary declines in market value recorded.

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).

	Aggregate Unrealized Loss		Aggregate Related Fair Value	
	Less than 12 months	12 months or longer	Less than 12 months	12 months or longer
2005:				
Available for sale equity securities	\$ 215	\$ 282	\$ 1,731	\$ 1,423
2004:				
Available for sale equity securities	\$ 181	\$ 75	\$ 2,934	\$ 362

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. At December 31, 2005, nine available-for-sale securities were in an unrealized loss position. At December 31, 2004, ten available-for-sale securities were in an unrealized loss position. At December 31, 2005 two available-for-sale securities had unrealized loss positions of greater than 20 percent. Both securities exceeded 20 percent for fewer than nine months. IPC does not consider these investments to be other-than-temporarily impaired at December 31, 2005 or 2004.

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14. ASSET RETIREMENT OBLIGATIONS:

On January 1, 2003, IPC adopted SFAS 143, "Accounting for Asset Retirement Obligations." This statement addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. An obligation may result from the acquisition, construction, development or the normal operation of a long-lived asset. SFAS 143 requires an entity to record the fair value of a liability for an asset retirement obligation (ARO) in the period in which it is incurred. When the 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 at that time. As a rate-regulated entity, IPC records regulatory assets and 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.

In 2005, IPC adopted FIN 47. This Interpretation clarifies that the term "conditional asset retirement obligation," as used in FASB Statement No. 143, refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and/or method of settlement. Thus, the timing and/or method of settlement may be conditional on a future event. Accordingly, an entity is required to recognize a liability for the fair value of a conditional ARO if the fair value of the liability can be reasonably estimated. The fair value of a liability for the conditional ARO should be recognized when incurred—generally upon acquisition, construction, or development and/or through the normal operation of the asset. Uncertainty about the timing and/or method of settlement of a conditional ARO should be factored into the measurement of the liability when sufficient information exists. FAS 143 acknowledges that, in some cases, sufficient information may not be available to reasonably estimate the fair value of an ARO. The Interpretation also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an ARO.

FIN 47 became effective December 31, 2005. After reviewing the provisions of FIN 47, no significant additional AROs were identified at IPC.

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. As of December 31, 2005, IPC had \$153 million of such costs recorded as regulatory liabilities on its Balance Sheet.

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

	2005	2004
Balance at beginning of year	\$ 9,288	\$ 7,140
Amount recorded on adoption		-
Accretion expense	531	421
Revisions in estimated cash flows	260	1,727
Balance at end of year	\$ 10,079	\$ 9,288

15. RELATED PARTY TRANSACTIONS:

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. IPC billed IDACORP \$4 million in each 2005 and 2004 for these services.

IDACOMM

IPC provides project management and engineering services to IDACOMM. IDACOMM also pays joint use fees to IPC. Total fees charged to IDACOMM were \$0.3 million per year in 2005 and 2004.

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Ida-West

IPC purchases all of the power generated by four of Ida-West's hydroelectric projects. IPC paid \$7 million per year in 2005 and 2004.

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**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)	3,477,521,238	3,477,521,238
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	3,477,521,238	3,477,521,238
9	Leased to Others		
10	Held for Future Use	2,906,206	2,906,206
11	Construction Work in Progress	149,814,313	149,814,313
12	Acquisition Adjustments	-454,449	-454,449
13	Total Utility Plant (8 thru 12)	3,629,787,308	3,629,787,308
14	Accum Prov for Depr, Amort, & Depl	1,364,640,116	1,364,640,116
15	Net Utility Plant (13 less 14)	2,265,147,192	2,265,147,192
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	1,333,025,502	1,333,025,502
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	31,919,472	31,919,472
22	Total In Service (18 thru 21)	1,364,944,974	1,364,944,974
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	-304,858	-304,858
33	Total Accum Prov (equals 14) (22,26,30,31,32)	1,364,640,116	1,364,640,116

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**SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION, AMORTIZATION AND DEPLETION**

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
					4
					5
					6
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Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

- Report below the original cost of electric plant in service according to the prescribed accounts.
- 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.
- Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
- 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.
- Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
- Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	5,703	62,527
3	(302) Franchises and Consents	10,169,022	9,848,216
4	(303) Miscellaneous Intangible Plant	66,579,839	4,038,091
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	76,754,564	13,948,834
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,282,073	88,246
9	(311) Structures and Improvements	130,003,136	430,783
10	(312) Boiler Plant Equipment	476,487,554	18,603,255
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	116,615,282	6,001,952
13	(315) Accessory Electric Equipment	61,106,974	69,847
14	(316) Misc. Power Plant Equipment	12,692,624	629,769
15	(317) Asset Retirement Costs for Steam Production	2,775,120	858,214
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	800,962,763	26,682,066
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	13,935,723	2,256
28	(331) Structures and Improvements	129,090,704	1,003,010
29	(332) Reservoirs, Dams, and Waterways	243,405,546	592,572
30	(333) Water Wheels, Turbines, and Generators	185,352,429	335,134
31	(334) Accessory Electric Equipment	36,199,922	291,218
32	(335) Misc. Power PLant Equipment	14,166,220	678,800
33	(336) Roads, Railroads, and Bridges	6,950,430	
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	629,100,974	2,902,990
36	D. Other Production Plant		
37	(340) Land and Land Rights	219,037	183,708
38	(341) Structures and Improvements	1,207,423	4,131,377
39	(342) Fuel Holders, Products, and Accessories	1,676,666	1,842,209
40	(343) Prime Movers	765,800	28,604,602
41	(344) Generators	43,894,011	17,046,301
42	(345) Accessory Electric Equipment	2,177,547	2,502,829
43	(346) Misc. Power Plant Equipment	2,512,876	

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

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

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

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

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)	Line No.
				1
			68,230	2
620,693			19,396,545	3
20,339,949			50,277,981	4
20,960,642			69,742,756	5
				6
				7
			1,370,319	8
40,709			130,393,210	9
1,535,903			493,554,906	10
				11
112,068			122,505,166	12
47,352			61,129,469	13
379,322			12,943,071	14
			3,633,334	15
2,115,354			825,529,475	16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
13,507			13,924,472	27
49,560			130,044,154	28
			243,998,118	29
			185,687,563	30
26,507			36,464,633	31
28,652			14,816,368	32
			6,950,430	33
				34
118,226			631,885,738	35
				36
			402,745	37
			5,338,800	38
			3,518,875	39
			29,370,402	40
			60,940,312	41
			4,680,376	42
1,171,473			1,341,403	43

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	52,453,360	54,311,026
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,482,517,097	83,896,082
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	22,409,168	2,462,366
49	(352) Structures and Improvements	31,307,239	1,839,179
50	(353) Station Equipment	228,308,784	12,798,478
51	(354) Towers and Fixtures	76,573,247	2,788,332
52	(355) Poles and Fixtures	89,925,076	2,844,357
53	(356) Overhead Conductors and Devices	111,461,261	4,495,795
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)	560,303,126	27,228,507
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	3,444,009	3,704,212
61	(361) Structures and Improvements	18,722,119	1,178,329
62	(362) Station Equipment	129,850,071	9,530,868
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	185,762,953	6,005,448
65	(365) Overhead Conductors and Devices	94,136,122	2,858,254
66	(366) Underground Conduit	39,213,897	2,535,196
67	(367) Underground Conductors and Devices	147,815,584	6,688,731
68	(368) Line Transformers	272,981,978	25,057,535
69	(369) Services	46,412,203	2,506,649
70	(370) Meters	47,456,634	4,465,727
71	(371) Installations on Customer Premises	2,483,682	123,267
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	3,968,946	101,932
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	992,248,198	64,756,148
76	5. GENERAL PLANT		
77	(389) Land and Land Rights	8,562,258	41,571
78	(390) Structures and Improvements	60,206,722	1,399,785
79	(391) Office Furniture and Equipment	52,007,353	3,192,812
80	(392) Transportation Equipment	43,831,169	4,823,363
81	(393) Stores Equipment	1,006,913	23,859
82	(394) Tools, Shop and Garage Equipment	3,832,595	427,676
83	(395) Laboratory Equipment	9,230,030	307,002
84	(396) Power Operated Equipment	6,324,623	1,080,983
85	(397) Communication Equipment	26,100,726	1,805,565
86	(398) Miscellaneous Equipment	2,344,859	328,900
87	SUBTOTAL (Enter Total of lines 77 thru 86)	213,447,248	13,431,516
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)	213,447,248	13,431,516
91	TOTAL (Accounts 101 and 106)	3,325,270,233	203,261,087
92	(102) Electric Plant Purchased (See Instr. 8)		
93	(Less) (102) Electric Plant Sold (See Instr. 8)		
94	(103) Experimental Plant Unclassified		
95	TOTAL Electric Plant in Service (Enter Total of lines 91 thru 94)	3,325,270,233	203,261,087

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.
				44
1,171,473			105,592,913	45
3,405,053			1,563,008,126	46
				47
63,565			24,807,969	48
11,613			33,134,805	49
5,258,014			235,849,248	50
67,152			79,294,427	51
568,129			92,201,304	52
1,181,484			114,775,572	53
				54
				55
			318,351	56
				57
7,149,957			580,381,676	58
				59
			7,148,221	60
6,389			19,894,059	61
915,843			138,465,096	62
				63
1,313,589			190,454,812	64
743,922			96,250,454	65
138,568			41,610,525	66
642,799			153,861,516	67
4,353,657			293,685,856	68
358,959			48,559,893	69
1,533,378			50,388,983	70
46,653			2,560,296	71
				72
70,098			4,000,780	73
				74
10,123,855			1,046,880,491	75
				76
			8,603,829	77
231,812			61,374,695	78
5,576,917			49,623,248	79
1,123,846			47,530,686	80
57,011			973,761	81
94,926			4,165,345	82
276,735			9,260,297	83
142,602			7,263,004	84
1,815,773			26,090,518	85
50,953			2,622,806	86
9,370,575			217,508,189	87
				88
				89
9,370,575			217,508,189	90
51,010,082			3,477,521,238	91
				92
				93
				94
51,010,082			3,477,521,238	95

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ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

- 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.
- 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			224,961
4	Transmission Stations			360,819
5	Transmission Lines			73,987
6	Distribution Stations			1,099,877
7				
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:			
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47	Total			2,906,206

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	ROLLUP RELIC COST BROWNLEE	27,824,175
2	ROLLUP RELIC COST HELLS CANYON	19,159,112
3	ROLLUP RELIC COST OXBOW	8,680,393
4	DALY CREEK PROPERTY ACQUISITIO	5,728,032
5	HELLS CANYON RELICENSING OUTSI	4,018,846
6	KINPORT CONDENSER REPAIR	3,455,692
7	LINE 470 HRFT-STKY 138 KV	2,795,293
8	NAMPA - ADD 230KV TRANSFORMER	2,749,836
9	BRIDGER UNDISTRIBUTED WORK ORD	2,675,648
10	CIAC LIABILITY RECLASS	2,569,896
11	WOOD RIVER VALLEY OPERATIONS C	2,441,599
12	LINE #470, 2ND 138KV LINE TO M	2,379,559
13	VALMY UNDISTRIBUTED WORK ORDER	2,276,735
14	STKY 138KV SWITCHING STATION	1,910,705
15	EKRT - BUILD NEW 138-34.5 KV E	1,708,083
16	EMS/ADVANCED APPLICATION PROJE	1,607,994
17	AP ACCRUAL ESTIMATE	1,565,176
18	TERR HELLS CANYON RELICENSING-	1,280,278
19	PAHSIMEROI HATCHERY EXPANSION	1,278,468
20	COTTONWOOD PROPERTY ACQUISITIO	1,167,240
21	ADEL UPGRADE AFTS LINE TERMINA	1,163,230
22	HCC ENGINEERING RELICESNING ST	1,154,093
23	HCC RELICENSING FISH2004 FEASI	1,143,982
24	HTSU ADD BORA & MPSN 230KV LIN	1,138,174
25	SNMW0401 EQUIP OLD QWEST SITE	1,121,467
26	VALMY 32247 COAL CAR THAW STAT	1,108,169
27	NAMPA TAP ROW ACQUISITION	1,086,814
28	WQ ONGOING HELLS CANYON RELICE	1,073,692
29	342 COST CENTER DELIVERY CAPIT	978,822
30	BORAH - NEW 345KV, 150 MVAR CA	942,878
31	CUMW EQUIP OLD QWEST SITE	905,823
32	BRIDGER 2006C002 REWIND U1 MAI	899,144
33	MIDPOINT - NEW 345KV, 175 MVAR	893,973
34	REL-HELLS CANYON COMPLEX FY200	855,238
35	BOARDMAN UNDISTRIBUTED WORK OR	751,638
36	HAPPY VALLEY SUBSTATION	724,182
37	RELICENSING: HCC SEDIMENT & GE	707,009
38	MEGG-SQCK REBUILD TO 4/0 AC	697,780
39	HCC SUPPORT	696,287
40	CAPITALIZED SPARE PARTS 2004 D	620,872
41	LINE 722, CONSTRUCT NEW BORAH-	583,305
42	VALMY 31818 U1 DCS UPGRADE PRO	565,387
43	TOTAL	149,814,313

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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	418-CC DELIVERY CAPITAL OVERHE	551,124
2	WM-HELLS CANYON CONTINUED STUD	549,373
3	Line 722, ROW/Easements	537,602
4	IPCO- 2005 BOISE DOWNTOWN CAPT	495,841
5	IPCO-KARCHER RD EXIT RELOCATIO	492,447
6	REL-HCC SEDIMENTATION STUDIES	487,106
7	COST CENTER 316 DELIVERY CAPIT	459,709
8	FSH-DEV. WHITE STURGEON CONSER	457,439
9	HCC RELICENSING, FISH2004 REDB	444,903
10	HELLS CANYON COMPLEX	432,876
11	HCC RESERVOIR/DISCHARGE WQ	424,350
12	390 COST CENTER DELIVERY CAPIT	424,232
13	HELLS CANYON RELICENSING	418,514
14	RIGHT OF WAY, LINE 470, HORSE	416,925
15	336-COST CENTER DELIVERY CAPIT	412,839
16	HCC RELICENSING, FISH2004 ANAD	401,609
17	LINE #438 CDAL-LCST IMPROVE RO	393,385
18	FISH-HCC-REDBAND TROUT/BULL TR	390,502
19	CONSTRUCTION ACCOUNTING CAPITA	386,353
20	360 COST CENTER DELIVERY CAPIT	364,137
21	FISH-HELLS CANYON INSTREAM FLO	361,010
22	BRIDGER 2006C005 REFURBISH U2	340,221
23	WM STREAMFLOW FORECAST MODEL P	334,318
24	343 COST CENTER DELIVERY CAPIT	330,974
25	410-CC DELIVERY CAPITAL OVERHE	330,892
26	HAILEY TEAM CAP OH WORK ORDER	317,292
27	415-CC DELIVERY CAPITAL OVERHE	315,513
28	VALMY 31647 NUCLEAR COAL ANALY	306,143
29	IPCO-CSCD-013 REBUILD FROM CAS	306,125
30	LINE 441MODIFICATION FOR LINE4	298,314
31	IPCO-CSCD-011 REBUILD SOUTH AR	297,482
32	BSU SECOND FEEDER-INSTALL SECO	296,414
33	REL-HCC OREGON REAUTHORIZATION	296,119
34	SERVER CONSOLIDATION	295,064
35	BRIDGER 2005C013 REVERSE OSMOS	293,422
36	CALL CENTER LABOR HOURS FOR LI	293,386
37	324-COST CENTER DELIVERY CAPIT	289,597
38	REL - SWAN FALLS FY2004 CAPITA	285,136
39	HTSU0101 REPLACE C131 CAP BANK	283,000
40	INTRUSION DETECTION SYSTEM UPD	281,542
41	UNIT 6711-6X6 57-72' MAT HANDL	281,304
42	MPSN REPLACE RELAYING ON MPSN-	276,841
43	TOTAL	149,814,313

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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	BRIDGER 2006C010 U1 SUBMERGED	276,685
2	PAYROLL & IBNR ACCRUAL	276,639
3	STORAGE GROWTH	276,203
4	BARBER FLATS LAND SWAP-OXBOW	275,852
5	BRIDGER 2004C027 UPGRADE GREEN	275,815
6	LEGAL DEPT LABOR: HELLS CANYON	273,154
7	HCC RELICENSING, FISH2004 INST	272,897
8	Delivery Overheads	269,832
9	578 COST CENTER DELIVERY CAPIT	269,053
10	OXMW0401 INSTALL RADIO & TOWER	268,104
11	RELICENSING: SWAN FALLS	266,487
12	ST AL'S - INSTALL DUCT VAULT S	262,276
13	WQ-HCC TMDL/401-2003-CAPITAL	258,575
14	REL HCC BAKER COUNTY SETTLEMEN	258,505
15	TAMARACK RESORT-WHITEWATER SUB	251,878
16	CAPITAL OVERHEADS FOR CADD & A	249,923
17	IPCO/HALY-015/F-18 TO IC-12 -	240,371
18	FISH-HCC-ANADROMOUS FISH BELOW	236,453
19	HCPR0501 UWAVE RADIO & ANT	234,088
20	392 COST CENTER DELIVERY CAPIT	233,596
21	SWAN FALLS RELICENSING	232,490
22	404 COST CENTER DELIVERY CAPIT	232,001
23	DEVCON CONST-SERVICE FOR NEW B	231,246
24	FIR GROVE ESTATES-121 LOT SUBD	230,711
25	COST CENTER 317 DELIVERY CAPIT	230,548
26	COST CENTER 310 DELIVERY CAPIT	230,266
27	577 COST CENTER DELIVERY CAPIT	227,446
28	NEW UNIT 6707-LINEBED COC	224,583
29	100-COST CENTER DELIVERY CAPIT	221,959
30	REC-HCC RELICENSING PROCESS	214,597
31	LN 426, EMERGENCY REPAIRS CAUS	212,827
32	370 -COST CENTER DELIVERY CAPI	210,053
33	GOODING TEAM CAP OH WORK ORDER	209,661
34	575 COST CENTER DELIVERY CAPIT	209,367
35	METER MTF WO FOR NEW INSTALLAT	203,466
36	ADAMSFAM TEAM CAP OH WORK ORDE	201,428
37	POPULATION VIABILITY MODEL - O	199,810
38	BOISE BENCH - KING 138 KV LINE	198,349
39	420-CC DELIVERY CAPITAL OVERHE	198,002
40	TWINWEST TEAM CAP OH WORK ORDE	196,058
41	335-COST CENTER DELIVERY CAPIT	195,903
42	334-COST CENTER DELIVERY CAPIT	194,956
43	TOTAL	149,814,313

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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	FISH HELLS CANYON RELICENSING	194,687
2	COST CENTER 320 DELIVERY CAPIT	194,439
3	IPCO/STAR-013/UNDERBUILD EAGL-	191,453
4	LINE 438, RIGHT OF WAY, VICTOR	189,236
5	TOOL EXP TRANS TO CONST	188,428
6	RELOCATE ON POLELINE RD IN TWI	186,721
7	HCC RELICENSING FISH2004 RESID	186,515
8	326-COST CENTER DELIVERY CAPIT	185,880
9	NEW UNIT 6706-55' BUCKET - COC	183,708
10	WILS SUBSTATION CONSTRUCTION	182,677
11	EDEN - REPLACE 101Z & 102Z	181,092
12	ENVIRONMENTAL DATABASE - 2005	180,213
13	COST CENTER 318 DELIVERY CAPIT	179,512
14	NEW UNIT 6719 (CC 345) ADDL CR	178,660
15	PQ AG DSR LAB EQUIPMENT-ION	176,203
16	KING - REPLACE PCB SHUNT CAPAC	173,613
17	327-COST CENTER DELIVERY CAPIT	172,690
18	HULN UPGRADE FEEDER RELAYING &	172,359
19	COST CENTER 321 DELIVERY CAPIT	171,430
20	WESR0402 011&012 GETAWAYS	170,247
21	OLYMPIC TERRACE- 631 N WASHING	169,252
22	328-COST CENTER DELIVERY CAPIT	169,046
23	SNBK RADIO & ANT	167,948
24	ACHD/IPCO FRANKLIN ROAD REBUI	166,390
25	OREGON REAUTHORIZATION - HELLS	164,543
26	BRIDGER 2006C001 U1 CONTROLS R	164,220
27	OMS UPGRADE OPSCENTRICITY 1.7.	164,102
28	PEAKING RESOURCE RFP - 2007 CT	163,260
29	EXPANSION OF EXISTING TWIN FAL	162,409
30	SWAN FALLS RELICENSING FISH200	157,204
31	REL-HCC OREGON HART 2004 CAPIT	155,453
32	COM - REC BAKER CO SETTLEMENT	155,352
33	375 COST CENTER DELIVERY CAPIT	153,225
34	DELIVERY CAPITAL OVERHEADS FOR	152,587
35	WQ SWAN FALLS RELICENSING-CAPI	151,447
36	REC-BLISS AREA LAND OPTION & P	150,168
37	WQ-HCC MITIGATION-RESERVOIR AE	149,817
38	337-COST CENTER DELIVERY CAPIT	149,368
39	REL - REC SWAN FALLS RELICENSI	148,194
40	PHEASANT MEADOWS SUBD #1-123 L	147,697
41	CHQ 9 EXECUTIVE AREA REMODEL	145,345
42	MIDPOINT 500 KV LINE RELAY REP	144,031
43	TOTAL	149,814,313

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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	#3 TURBINE RUNNER PURCHASE (IN	142,107
2	TERR HELLS CANYON COMPLEX TRAN	141,462
3	HCC WILDLIFE AND BOTANICAL	141,008
4	210-COST CENTER DELIVERY CAPIT	140,549
5	MISCELLANEOUS DELIVERY HARDWAR	140,307
6	SWAN FALLS RELICENSING INITIAL	136,910
7	OPERATIONAL DATA STORE	135,985
8	PURCHASE BUCKET TRUCK 6713 -	135,091
9	NEW BUCKET TRUCK 6714 - FARW	135,091
10	NEW BUCKET TRUCK 6715 - NORT	135,091
11	NEW BUCKET TRUCK 6716 - SOUTH	135,091
12	NEW BUCKET TRUCK 6717 - OREGO	134,969
13	NEW BUCKET TRUCK 6718 - CENT	134,967
14	WHISPERING PINES SUBDV. - POWE	132,920
15	377 -COST CENTER DELIVERY CAPI	130,242
16	IPCO CABLE REPLACEMENT BOBN-04	129,812
17	FISH-HCC-RESIDENT FISH-2003-CA	128,074
18	WQ-HCC MITIGATION-TURBINE VENT	127,726
19	TFEAST TEAM CAP OH WORK ORDER	127,219
20	153 COST CENTER DELIVERY CAPIT	126,939
21	INSTANT MESSAGING GATEWAY	126,786
22	REC-SWAN FALLS RELICENSING PRO	126,138
23	MINI CASSIA TEAM CAP OH WORK O	126,006
24	CDWL-WILLIS 138 KV LINE CONSTR	124,232
25	REL - GEOMORPHOLOGY	124,208
26	BRIDGER 2006C022 PURCH SPARE U	120,486
27	CDWL-WILS TRANSMISSION & ROW	120,396
28	VINEYARD POINTE SUBDIVISION #2	120,068
29	IDAHO NATIONAL GUARD- STAGE ST	119,434
30	CDAL018 - ADD NEW FEEDER	117,141
31	REL - REC HCC RELICENSING PROC	116,712
32	BUILD 138-KV LINE-CHUT TO HPVY	116,678
33	OXBOW FISH HATCHERY EXPANSION	113,612
34	378 -COST CENTER DELIVERY CAPI	112,091
35	FIREWALL CLUSTER IMPROVEMENTS	111,700
36	381 -COST CENTER DELIVERY CAPI	111,499
37	HR COMPETENCY MANAGEMENT SYSTE	109,322
38	FISH-HCC-FEASIBILITY OF REINTR	108,641
39	BOMT-REPLACE T131	107,338
40	376 -COST CENTER DELIVERY CAPI	106,482
41	BKAT-MRDN CONVERT T202 TO 138K	105,473
42	LINE #602, BLACKFOOT-GOSHEN 16	103,580
43	TOTAL	149,814,313

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CONSTRUCTION WORK IN PROGRESS -- ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
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Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	50CFS SPILLWAY MIN FLOW MODS (103,564
2	BRIDGER 2006C042 U2 ADV SOOTBL	103,227
3	BRIDGER 2006C027 U2 BCP REBUIL	102,711
4	IPCO-NEW 35KV RISER FOR EKRT 0	100,348
5	IPCO- 2005 DOWNTOWN CAPTIAL IM	100,271
6	Other Minor Work Orders	-7,973,977
7	Construction WIP CIAC Contra	2,279,578
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43	TOTAL	149,814,313

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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	1,272,087,500	1,272,087,500		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	93,229,629	93,229,629		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	2,560,095	2,560,095		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9	Fuel Stock	108,409	108,409		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	95,898,133	95,898,133		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	28,813,920	28,813,920		
13	Cost of Removal	3,084,965	3,084,965		
14	Salvage (Credit)	2,161,520	2,161,520		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	29,737,365	29,737,365		
16	Other Debit or Cr. Items (Describe, details in footnote):	-5,222,766	-5,222,766		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,333,025,502	1,333,025,502		
Section B. Balances at End of Year According to Functional Classification					
20	Steam Production	404,798,819	404,798,819		
21	Nuclear Production				
22	Hydraulic Production-Conventional	228,958,005	228,958,005		
23	Hydraulic Production-Pumped Storage				
24	Other Production	8,282,764	8,282,764		
25	Transmission	200,078,275	200,078,275		
26	Distribution	400,254,012	400,254,012		
27	General	90,653,627	90,653,627		
28	TOTAL (Enter Total of lines 20 thru 27)	1,333,025,502	1,333,025,502		

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FOOTNOTE DATA			

Schedule Page: 219 Line No.: 14 Column: c
Relocation reimbursements, Up and down costs and damage and insurance claims \$ 463,286.

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

Accumulated Provision for Depreciation on Asset Retirement Obligation	\$ (56,808)
Embedded removal in Accumulated provision for Depreciation	4,983,275
Disallowed capital cost from the 2003 Idaho rate case	296,299

	\$5,222,766

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INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

- Report below investments in Accounts 123.1, investments in Subsidiary Companies.
- 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)
 - Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
 - 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.
- 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			34,081,386
5				
6	Subtotal Idaho Energy Resources			36,544,480
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42	Total Cost of Account 123.1 \$	2,463,093	TOTAL	36,544,480

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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 from investments, including such revenues from securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if 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
6,967,929		41,049,315		4
				5
6,967,929		43,512,409		6
				7
				8
				9
				10
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				41
6,967,929		43,512,409		42

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of <u>2005/Q4</u>
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MATERIALS AND SUPPLIES

- 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.
- 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)	6,450,733	11,494,190	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)	10,372,441	11,238,406	
8	Transmission Plant (Estimated)	4,805,201	4,465,632	
9	Distribution Plant (Estimated)	10,171,811	12,235,598	
10	Assigned to - Other (provide details in footnote)	29,324	766,156	
11	TOTAL Account 154 (Enter Total of lines 5 thru 10)	25,378,777	28,705,792	Electric
12	Merchandise (Account 155)			
13	Other Materials and Supplies (Account 156)			
14	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
15	Stores Expense Undistributed (Account 163)	685,830	1,745,428	Electric
16				
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	32,515,340	41,945,410	

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Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of <u>2005/Q4</u>
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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		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	None					
2						
3						
4						
5						
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14						
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17						
18						
19						
20	TOTAL					

Name of Respondent Idaho Power Company		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/18/2006		Year/Period of Report End of <u>2005/Q4</u>	
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		Balance at End of Year (f)	
				Account Charged (d)	Amount (e)		
21	None						
22							
23							
24							
25							
26							
27							
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48							
49	TOTAL						

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than \$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		Balance at end of Current Quarter/Year (f)
				Written off During the Quarter/Year Account Charged (d)	Written off During the Period Amount (e)	
1	Asset Retirement Obligations - IPUC	8,372,493	559,457	Footnote	568,762	8,363,188
2	Order #29414 - OPUC Order #04-585					
3						
4	Postretirement Benefits - IPUC order #25550	45,400		401	45,400	
5	(amort period 2/95 thru 01/05)					
6						
7	Reorganization Costs - IPUC order 26216	754,055		401	754,055	
8	OPUC order #95-1262 (amort 01/96 thru 12/05)					
9						
10	Regulatory Unfunded Accumulated Deferred Income Tax	344,219,574	10,686,489	282	8,789,430	346,116,633
11						
12	Power Cost Adjustment - IPUC order	34,009,371	89,661,801	Footnote	90,409,992	33,561,270
13	#27660 (amort period 6/05 thru 5/07)					
14						
15	Idaho - Demand Side Management - IPUC order	17,834,351		401	3,242,604	14,591,747
16	#27660 (amort period 7/98 thru 6/10)					
17						
18	Excess Power Amortization - Oregon	12,047,497	845,447	Footnote	4,401,825	8,411,119
19	(Capped at 10% per year until full amort)					
20						
21	Security Costs 2001-2002 (Amort period 1/03 - 12/07)	553,393		401	178,284	375,109
22						
23	Security Costs 2003 - IPUC Order #28975	259,783	4,648	401	64,591	199,840
24						
25	Professional Fees - IPUC order #29505	60,166	1,038	4073	19,944	41,260
26	(Amort period 1/03 thru 12/07)					
27						
28	Tax Settlement - IPUC Order 29601	7,118,562	4,577,501	4073	6,702,106	4,993,957
29	(Amort period 6/05 thru 5/06)					
30						
31	Cloud Seeding - IPUC Order 29670	182,954	671,106	1823	854,060	
32	(Included in PCA Amortization)					
33						
34	Irrigation Lost Revenue - IPUC Order 29669	13,289,763	193,120	1823	13,482,883	
35	(Included in PCA Amortization)					
36						
37	PCA Unbilled Amortization Reserve			4073	1,309,994	-1,309,994
38	(Reversed June 2006)					
39						
40	Excess Power Deferred - Oregon (see lines 18-19)		2,958,704	401	79,258	2,879,446
41						
42	Minor items (5)	33,466	49,521	Various	65,372	17,615
44	TOTAL	438,780,828	110,208,832		130,748,470	418,241,190

Name of Respondent Idaho Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report 2005/Q4
FOOTNOTE DATA			

Schedule Page: 232 Line No.: 1 Column: e

107	557,501
108	<u>11,261</u>
	568,762

Schedule Page: 232 Line No.: 12 Column: e

1823	35,495,679
253	166,667
254	7,495,327
401	38,764,814
4073	8,159,398
4210	16,292
431	<u>11,725</u>
	90,109,902

Schedule Page: 232 Line No.: 18 Column: e

254	100,000
401	4,371,602
4210	<u>10,223</u>
	4,481,825

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than \$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		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1	Regional Transmsn Org - (RTO)	2,251,115	956,225	Footnote	956,225	2,251,115
2						
3	Advance prepaid coal royalties	2,176,829		131	200,776	1,976,053
4						
5	Benefits plan - intangible asst	1,681,824		219	268,571	1,413,253
6						
7	Security plan	28,175,826	1,938,529	4262	1,528,870	28,585,485
8						
9	American Falls bond refinance	293,470		401	14,552	278,918
10						
11	Prepaid Credit Facility		1,037,592	165	413,870	623,722
12						
13	Company owned Life Insurance	7,589,538	894,978	Footnote	1,669,180	6,815,336
14						
15	American Falls water rights	19,885,000				19,885,000
16						
17	Milner bond guarantee	11,700,000				11,700,000
18						
19	Southwest intertie project -	6,286,106	54,956	232	7,671	6,333,391
20	right of way costs					
21						
22	CSPP receivable	1,389,261		143	372,414	1,016,847
23						
24	American Falls - bond refinance	967,982		401	47,999	919,983
25	(35 year amortization)					
26						
27	Transmission Deposit-PacifiCorp	151,875	143,500			295,375
28						
29	Shelf Registration	583,377	13,049	Footnote	596,426	
30						
31	Customer Svcs Finance Program	140,130	309,406	Footnote	405,265	44,271
32						
33	Minor Items & Job Orders (7)	517	32,188,208	Various	32,240,022	-51,297
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	83,272,850				82,087,452

Name of Respondent Idaho Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report 2005/Q4
FOOTNOTE DATA			

Schedule Page: 233 Line No.: 1 Column: d

186	295,030
232	6,821
401	654,374
	<u>956,225</u>

Schedule Page: 233 Line No.: 13 Column: d

131	773,387
4262	895,793
	<u>1,669,180</u>

Schedule Page: 233 Line No.: 29 Column: d

131	66
181	585,758
186	10,446
401	154
	<u>596,426</u>

Schedule Page: 233 Line No.: 31 Column: d

131	153,744
141	243,905
142	7,616
	<u>405,265</u>

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Idaho Power Company	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	(Mo, Da, Yr) 04/18/2006	2005/Q4
FOOTNOTE DATA			

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

Other:	Beginning Balance	Ending Balance
Senior Management Security Plan	9,977,023	10,851,325
Minimum Pension Liability	3,482,678	3,947,905
Rate Case Disallowance	3,432,123	3,316,285
Micron - CIAC	2,717,223	2,477,838
Other Employee's Long Term Deferred Compensation	2,346,500	2,424,225
Post Retiree Benefits - VEBA	867,675	1,893,065
SFAS112 - Post Retirement Benefits	1,157,160	1,037,355
Non - VEBA Pension and Benefits	926,069	905,653
Meridian Gold Contributions	241,128	219,017
Restricted Stock Plan	275,929	215,673
Linden Feeder Deposits	-	128,814
Dark Fiber Contracts	101,285	101,285
Other Regulatory Liabilities	53,000	83,990
Start-up and Organization Costs	75,447	75,447
Seattle City Light - CIAC	80,030	48,241
Loss on Pioneer Land Write - down	45,351	45,351
FERC Settlement Reserve	781,900	-
SHOBAN Transmission Right of Way Expense	339,874	-
SMSP - Market Change of Rabbi Investments	7,027	-
	26,907,422	27,771,469

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of <u>2005/Q4</u>
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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	
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Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.

4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.

5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.

Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
Shares (e)	Amount (f)	AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
		Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
39,150,812	97,877,030					2
						3
39,150,812	97,877,030					4
						5
						6
						7
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Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

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

- (a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
- (b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
- (c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
- (d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

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

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of <u>2005/Q4</u>
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CAPITAL STOCK EXPENSE (Account 214)

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

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Stock	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 Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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LONG-TERM DEBT (Account 221, 222, 223 and 224)

- 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.
- In column (a), for new issues, give Commission authorization numbers and dates.
- For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
- 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.
- For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
- In column (b) show the principal amount of bonds or other long-term debt originally issued.
- In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
- 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.
- 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	807,871
7			
8	7.20% Series due 2009	80,000,000	572,246
9			
10	5.30% Series Due 2035 (Idaho IPC-E-04-22	60,000,000	408,411 D
11	OPUC UF 4211 WPSC 2005-ES-04-27)		
12			
13			
14	5.83% Series due 2005	60,000,000	2,508,801
15			
16	6.60% Series due 2011	120,000,000	860,502
17			
18	4.25%Series due 2013	70,000,000	641,201
19			374,500 D
20			
21	4.75% Series due 2012	100,000,000	944,356
22			1,047,617 D
23			
24	6.00% Series due 2032	100,000,000	1,069,356
25			543,244 D
26			
27	5.875% Series due 2034	55,000,000	524,419
28			383,322 D
29			
30	5.50% Series due 2034	50,000,000	746,961 D
31			
32	Pollution control Revenue Bonds		
33	TOTAL	1,047,045,000	15,375,604

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
						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	12/1/07	12/1/00	12/1/07	80,000,000	5,904,000	6
						7
11/23/99	12/1/09	1/1/00	1/1/10	80,000,000	5,760,000	8
						9
08/26/05	08/26/35	08/26/05	08/26/35	60,000,000	1,104,167	10
						11
						12
						13
09/09/98	09/09/05	09/09/98	09/09/05		2,409,733	14
						15
03/02/01	03/02/11	03/02/01	03/02/11	120,000,000	7,920,000	16
						17
05/01/03	10/01/13	05/01/03	09/29/13	70,000,000	2,975,000	18
						19
						20
11/15/02	11/15/12	11/15/02	11/15/12	100,000,000	4,750,000	21
						22
						23
11/15/02	11/15/32	11/15/02	11/15/32	100,000,000	6,000,000	24
						25
						26
8/16/04	8/16/34	8/16/04	8/16/34	55,000,000	2,750,000	27
						28
						29
3/26/04	3/15/34	3/26/04	3/15/34	50,000,000	3,224,481	30
						31
						32
				987,045,000	53,339,531	33

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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LONG-TERM DEBT (Account 221, 222, 223 and 224)

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	6.05% Series 96A due 2026	68,100,000	571,895
2			471,252 D
3			
4	Series 96B due 2026	24,200,000	124,587
5			
6	Series 96C due 2026	24,000,000	123,561
7			
8	Port of Morrow Variable due 2027	4,360,000	188,545
9			
10	Humboldt Variable due 2024	49,800,000	1,697,856
11			
12	Subtotal Account 221	1,015,460,000	15,375,604
13			
14	Account 224:		
15	Bond Guarantee - American Falls	19,885,000	
16			
17	Note Guarantee - Milner Dam	11,700,000	
18			
19	Subtotal Account 224	31,585,000	
20			
21	Account 222: Required Bonds		
22	Account 223: Advances for Associated Companies		
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	1,047,045,000	15,375,604

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
07/25/96	07/15/26	07/25/96	07/15/26	68,100,000	4,120,050	1
						2
						3
07/25/96	07/15/26	07/25/96	07/15/26	24,200,000	621,934	4
						5
07/25/96	07/15/26	07/25/96	07/15/26	24,000,000	613,815	6
						7
5/17/00	2/1/27	5/17/00	2/1/27	4,360,000	130,082	8
						9
10/22/03	12/01/24	11/01/03	12/01/24	49,800,000	1,206,269	10
						11
				955,460,000	53,339,531	12
						13
						14
4/26/00	2/1/25			19,885,000		15
						16
02/10/92				11,700,000		17
						18
				31,585,000		19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
				987,045,000	53,339,531	33

Name of Respondent Idaho Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report 2005/Q4
FOOTNOTE DATA			

Schedule Page: 256 Line No.: 14 Column: h

Redeemed in September 2005

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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 filed, 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)	71,838,830
2		
3		
4	Taxable Income Not Reported on Books	
5	Footnote	108,168,331
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10	Footnote	56,081,175
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15	Footnote	17,981,878
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	Footnote	16,373,074
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	201,733,384
28	Show Computation of Tax:	
29	Tentative Federal Tax @ 35%	70,606,684
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Name of Respondent Idaho Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report 2005/Q4
FOOTNOTE DATA			

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

004003-CONSTRUCTION ADV-252	4,354,239
004004-CIAC AS TAXABLE INC CLOSED TO PLANT	23,000,000
004005-AVOIDED COST INT CAP	2,653,876
004010-EMISSION ALLOWANCE-254.409-411	70,034,111
004013-CIAC AS TAXABLE INC IN ACCT 107	9,449,922
004016-CIAC TAXABLE INCOME-ACCT 253.575	(932,920)
004017-JOINT USE FEE REC'D B4 INC BOOKED-253.050	59,635
004018-LINDEN FEEDER DEPOSITS-253.206	200,658
004019-IDWR STREAMFLOW GUAGING CONTRACT-242.312	(10,002)
004501-ROYALTY INCOME BTL	109,000
004506-CIAC-MERIDIAN GOLD	(56,560)
004507-CIAC-MICRON-DRAM	(612,316)
004512-CIAC-SEATTLE CITY LIGHT	(81,312)
Total	108,168,331

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

Total Federal and State taxes deducted on books	42,050,522
005001-BAD DEBT EXPENSE	(530,188)
005008-GAIN/LOSS ON REACQUIRED DEBT-DEFERRED	549,856
005010-SFAS 112-POST-EMPLY BEN 182/253	(306,445)
005014-OVERACCRUED VACATION-ACCT 242	681,136
005017-INJURIES & DAMAGES	1,652,588
005019-DIRECTORS FEES DEF	257,414
005023-PENSION ACCR TO 926200	3,646,460
005024-MEALS (50% NON-DEDUCTIBLE) CHRGD TO R.E.	266,000
005025-MILNER FALLING WATER - REV ACCRL	264,100
005027-AMORTIZATION OF ACCOUNT 114	(22,723)
005028-OREGON OPER PROPERTY TAX ADJ	36,188
005033-NONVEBA PEN&BEN-Acct 228	(52,221)
005035-PCA EXPENSE DEFERRAL	7,287,698
005039-POST RETIREE BENEFIT- FAS106-ACCT 182	45,400
005044-RESTRICTED STOCK PLAN-COMP	177,044
005047-OTHER EMPLOYEE'S LT DEFERRED COMP-228	198,811
005049-253-FERC SETTLEMENT RESERVE	(2,000,000)
005050-186-BAD DEBT RESERVE-FINANCING PRGMS	440
005051-PUC ORDER 29505 - PROFESSIONAL FEES	18,906
005501-SEC PLAN-NET INS COSTS	(403,353)
005502-128-SMSP-MRKT CHG OF RABBI INVSTMNTS	(17,974)
005503-128-EDC-UNRLZD GN/LS FRM RABBI TRUST	(8,538)
005504-NONDEDUCTIBLE POLITICAL EXP-426.4	250,000
005505-SEC PLAN-BENEFIT ACCR	2,236,353
005516-NONDEDUCTIBLE POLITICAL EXP-O&M ACCTS	100,000
005531-RATE CASE DISALLOWANCES-REVERSE AMORT	(296,299)
Total	56,081,175

Name of Respondent Idaho Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report 2005/Q4
FOOTNOTE DATA			

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

007002-GAIN ON SALE OF BOC	31,970
007007-OTHER REGULATORY LIABILITIES-254	(79,268)
007501-REVERSE EQUITY EARNINGS OF SUBSIDIARIES	8,874,042
007502-ALLOWANCE FOR OFUDC	4,950,151
007503-ALLOWANCE FOR BFUDC	2,790,871
007504-RECLASS TAX EXEMPT INTEREST - FED & IDAHO	2,737
007504-RECLASS TAX EXEMPT INTEREST - FED ONLY	663,779
007514-COLI-INSURANCE PROCEEDS	747,596
Total	17,981,878

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

008001-VEBA-POST RET BNFTS-TRUST-ACCT 228	(2,622,821)
008009-DEPR FOR TAX GT OR LT BOOK	(2,309,259)
008015-INTEREST RATE HEDGE - 181.134	2,723,000
008020-CONSERVATION PROGRAMS	(3,242,613)
008025-MANUFACTURING DEDUCTION-ORE NOT ALLWD	3,498,529
008027-NEVADA OPERATING PROPERTY TAX ADJ	(22,609)
008034-REMOVAL COSTS	4,258,133
008035-REPAIR ALLOWANCE	5,000,000
008038-OREGON EXCESS PWR SUPPLY COSTS	(656,933)
008039-ST TAX-NOT DEDUCTED ON PRIOR RETURN	5,253
008041-AM FALLS - UNAMORTIZED DEBT EXP	(47,999)
008042-GAIN/LOSS ON REACQUIRED DEBT-FT	(610,841)
008045-ST TAX-AUDIT STLMNTS PAID THIS YR	1,144
008057-REORGANIZATION COSTS-ACCT 182	(754,055)
008071-PHOTOVOLTAIC STARTUP COSTS-ACCT 182	(1,984)
008072-INTANGIBLE ASSET-LABOR DEDUCT-107-FED ONLY	2,391,000
008074-INCREMENTAL SECURITY COSTS DEDUCTED	(238,227)
008077-PP INS & OTR EXP (1 YR OR LESS)-165	(338,557)
008501-COLI-TAX ADJ FROM BOOKS	(746,182)
008504-OREGON NONOP PROPERTY TAX ADJUST	(141)
008508-DEPR ADJ - NONOP - OTHER PROPERTY - NEW	8,255
0N10016-DIV PAID DED PUB UTIL	300,000
STATE INCOME TAX DEDUCTED ON FEDERAL RETURN	9,779,981
Total	16,373,074

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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 known, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b) amounts credited to 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 Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	Federal:					
2	Income	25,635,654		65,896,447	40,642,030	
3	Social Security - (FOAB)	338,547		9,333,954	9,320,596	
4	Unemployment	33,523		111,311	108,598	
5	Subtotal Federal	26,007,724		75,341,712	50,071,224	
6						
7	State of Idaho:					
8	Property	5,313,501		13,266,589	12,485,781	
9	Income	5,713,686		8,417,558	2,861,911	
10	KWH	90,271		1,408,414	1,402,524	
11	Unemployment	8,396		231,840	218,841	
12	Regulatory Commission			1,670,843	1,670,843	
13	Business License - Sho Ban		150	150	150	
14	Subtotal Idaho	11,125,854	150	24,995,394	18,640,050	
15						
16	State of Oregon					
17	Property		1,023,101	2,010,365	1,974,036	
18	Income	948,764		524,980	304,983	
19	Regulatory Commission			99,689	99,689	
20	Unemployment	1,768		20,132	21,043	
21	Franchise	120,381		481,887	479,634	
22	Subtotal Oregon	1,070,913	1,023,101	3,137,053	2,879,385	
23						
24	State of Montana:					
25	Property	40,115		93,497	86,918	
26	Subtotal Montana	40,115		93,497	86,918	
27						
28	State of Nevada:					
29	Property	220,963	441,929	865,897	1,064,253	
30	Unemployment	9			9	
31	Business Tax			241	241	
32	Subtotal Nevada	220,972	441,929	866,138	1,064,503	
33						
34	State of Wyoming					
35	Corporate License			3,043	3,043	
36	Property	443,504		992,799	939,830	
37	Subtotal Wyoming	443,504		995,842	942,873	
38						
39	misc states franchise					
40						
41	TOTAL	40,280,158	1,465,180	95,966,155	73,700,904	

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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 (i) 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
50,890,071		64,853,588			1,042,859	2
351,904		9,333,954				3
36,235		111,311				4
51,278,210		74,298,853			1,042,859	5
						6
						7
6,094,309		13,233,414			33,175	8
11,269,333		8,188,145			229,413	9
96,161		1,408,414				10
21,395		231,840				11
		1,670,843				12
	150					13
17,481,198	150	24,732,656			262,588	14
						15
	986,772	2,006,312			4,053	17
1,168,761		513,307			11,673	18
		99,689				19
856		20,132				20
122,634		481,887				21
1,292,251	986,772	3,121,327			15,726	22
						23
						24
46,694		93,497				25
46,694		93,497				26
						27
						28
	419,320	865,897				29
						30
		241				31
	419,320	866,138				32
						33
						34
		3,043				35
496,473		992,799				36
496,473		995,842				37
						38
						39
						40
72,183,706	1,406,242	94,640,941			1,325,064	41

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of <u>2005/Q4</u>
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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 known, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b) amounts credited to 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 Charged During Year (d)	Taxes Paid During Year (e)	Adjustments (f)
		Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)			
1	Other States Income	1,371,076		233,755	15,951	
2	Payroll Adjustment			-9,697,236		
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
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34						
35						
36						
37						
38						
39						
40						
41	TOTAL	40,280,158	1,465,180	95,966,155	73,700,904	

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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)	
1,588,880		229,864			3,891	1
		-9,697,236				2
						3
						4
						5
						6
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						40
72,183,706	1,406,242	94,640,941			1,325,064	41

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of <u>2005/Q4</u>
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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		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%	1,541,183				155,503	
4	7%						
5	10%	36,204,352				1,947,542	
6	11%	1,428,762				27,085	
7		27,661,860	411.4	5,373,779	411.4	1,293,533	
8	TOTAL	66,836,157		5,373,779		3,423,663	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Line 6 Col A 11%						
11							
12	State of Idaho	27,661,860	411.4	5,373,779	411.4	1,293,533	
13							
14							
15							
16							
17							
18							
19							
20							
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47							

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
1,385,680	9.91		3
			4
34,256,810	18.59		5
1,401,677	52.75		6
31,742,106	21.38		7
68,786,273			8
			9
			10
			11
31,742,106			12
			13
			14
			15
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			22
			23
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			48

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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OTHER DEFERRED 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		Credits (e)	Balance at End of Year (f)
			Contra Account (c)	Amount (d)		
1	Joint Pole Use	261,664	400	993,772	1,197,776	465,668
2						
3	Bureau of Land Mngt Rents/ROW		Footnote	273,316	5,285,116	5,011,800
4						
5	Point to Point Transmission Study	851,309	Footnote	150,963	429,584	1,129,930
6						
7	FTV	4,266,666	400	400,000	1,000,000	4,866,666
8						
9	Linden Feeder	128,831	N/A		200,658	329,489
10						
11	SWIP Deposit		N/A		600,000	600,000
12						
13	IDACOMM Dark Fiber		N/A		8,000	8,000
14						
15	Sho Ban Trans ROW		N/A		2,428,334	2,428,334
16						
17	Delivery Accruals		232	63,177	134,850	71,673
18						
19	Construction Work In Progress	932,920	107	1,015,313	2,652,289	2,569,896
20						
21	Customer Level Pay	2,137,600	232	1,875,957	873,461	1,135,104
22						
23	US Airforce Photovoltaic Generator	168,571	107	28,600	63,986	203,957
24						
25	Security Plan	25,519,945	Footnote	2,311,647	4,548,000	27,756,298
26						
27	FERC Settlement Reserve	2,000,000	Footnote	2,166,666	166,666	
28						
29	Milner Falling Water	3,192,857	N/A		264,100	3,456,957
30						
31	Postretirement Benefits	2,990,894	401	345,950	8,477	2,653,421
32						
33	Benefit Plan - Minimum Liability	10,590,068	N/A		921,420	11,511,488
34						
35	Directors Deferred Compensation	3,216,385	232	231,147	488,560	3,473,798
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	56,257,710		9,856,508	21,271,277	67,672,479

Name of Respondent Idaho Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report 2005/Q4
FOOTNOTE DATA			

Schedule Page: 269 Line No.: 3 Column: c

232	213,494
107	59,823
273,316	

Schedule Page: 269 Line No.: 5 Column: c

232	72,750
400	76,395
401	1,818
150,963	

Schedule Page: 269 Line No.: 25 Column: c

232	1,953,160
241	358,487
2,311,647	

Schedule Page: 269 Line No.: 27 Column: c

182	166,666
254	2,000,000
2,166,666	

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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 relating 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)	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			

NOTES

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
							2
							3
							4
							5
							6
							7
							8
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NOTES (Continued)

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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ACCUMULATED DEFERRED 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	224,926,950	14,067,218	12,714,856
3	Gas			
4	Other - See Note	360,356,125	-1,617,721	921,744
5	TOTAL (Enter Total of lines 2 thru 4)	585,283,075	12,449,497	13,636,600
6	Non-Operating Property	260,271		
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	585,543,346	12,449,497	13,636,600
10	Classification of TOTAL			
11	Federal Income Tax	494,281,323	12,242,919	13,636,600
12	State Income Tax	91,262,023	206,578	

NOTES

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
						226,279,312	2
							3
		182	2,473,547	182	4,370,605	359,713,718	4
			2,473,547		4,370,605	585,993,030	5
7,037						267,308	6
							7
							8
7,037			2,473,547		4,370,605	586,260,338	9
							10
5,903			2,164,356		4,370,605	495,099,794	11
1,134			309,191			91,160,544	12

NOTES (Continued)

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Name of Respondent Idaho Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report 2005/Q4
FOOTNOTE DATA			

Schedule Page: 274 Line No.: 4 Column: a

(282) "Other" Items <i>Line 4:</i>	2005	Changes during Year				Adjustments Debits		Adjustments Credits		2005
	Beginning Balance b	DR to 410.1 c	CR to 411.1 d	DR to 410.2 e	CR to 411.2 f	Acct. credited g	Amount h	Acct. debited i	Amount j	Ending Balance k
Repair Allowance	222,385		169,200							53,185
Bridger	427,257		102,400							324,857
N. Valmy	886,766		76,500							810,266
FERC Jurisdictional	7,818,502									7,818,502
Taxable CIAC in CWIP Bal.	(1,523,007)	(3,307,473)	900,166							(5,730,646)
CIAC Taxable Income-Acct 253,575	(326,522)	85,531	(326,522)							85,531
Misc Software Develop Costs	154,971	(999,462)								(844,491)
Intangible Asset-Labor Deduction FASB 109	8,476,197	2,603,683								11,079,880
	344,219,576					182	2,473,547	182	4,370,605	346,116,634
TOTAL	360,356,125	(1,617,721)	921,744	-	-		2,473,547		4,370,605	359,713,718

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ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3				
4				
5	Ferc Order 144A	-1,075,138		-550,082
6				
7				
8	Other - See Note	28,897,883	10,070,712	15,073,181
9	TOTAL Electric (Total of lines 3 thru 8)	27,822,745	10,070,712	14,523,099
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other - See Note	387,706		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	28,210,451	10,070,712	14,523,099
20	Classification of TOTAL			
21	Federal Income Tax	23,491,216	8,447,857	12,094,117
22	State Income Tax	4,719,235	1,622,855	2,428,982
23	Local Income Tax			

NOTES

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

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

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits			
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
							2
							3
							4
						-525,056	5
							6
							7
		219		219	59,916	23,955,330	8
					59,916	23,430,274	9
							10
							11
							12
							13
							14
							15
							16
							17
2,047	39,288					350,465	18
2,047	39,288				59,916	23,780,739	19
							20
1,717	32,950				50,262	19,863,985	21
330	6,338				9,654	3,916,754	22
							23

NOTES (Continued)

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Name of Respondent Idaho Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report 2005/Q4
FOOTNOTE DATA			

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

(283) Other Electric: Line 8:	2005	Changes during Year				Adjustments Debits		Adjustments Credits		2005
	Beginning Balance b	DR to 410.1 c	CR to 411.1 d	DR to 410.2 e	CR to 411.2 f	Acct. credited g	Amount h	Acct. debited i	Amount j	Ending Balance k
Loss on Reacquired Debt Conservation Programs	(1,014,614) 6,972,343	-	214,967 1,267,700							(1,229,581) 5,704,643
PCA Expense Deferral	15,845,093	9,292,173	12,141,298							12,995,966
PV Startup Costs	776	-	776							-
Post Retiree Benefits	17,749	-	17,749							-
Reorganization Costs	294,798	-	294,798							-
Incremental Security Costs	317,911	-	93,135							224,776
FERC Order 2000 Costs	880,073	-	-							880,073
Oregon Excess Power Costs	4,670,874	778,539	1,035,367							4,414,046
Professional Fees - IPUC Order 29505	23,522	-	7,391							16,131
Unrealized gains on Mkt Securities	889,358	-	-			219	-	219	59,916	949,274
TOTAL	28,897,883	10,070,712	15,073,181	-	-	-	-	59,916	23,955,330	

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

	Beginning Balance b	Changes during Year				Adjustments Debits		Adjustments Credits		Ending Balance k
		DR to 410.1 c	CR to 411.1 d	DR to 410.2 e	CR to 411.2 f	Acct. credited g	Amount h	Acct. debited i	Amount j	
Advance Coal Royalties	367,232			2,047	42,614					326,666
Oregon Non-Op Prop Tax Adj	820				12					808
Unrealized Gain/Loss From Rabbi Trust	19,654				(3,338)					22,991
Total	387,706	-	-	2,047	39,288	-	-	-	-	350,465

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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 Beginning of Current Quarter/Year (b)	DEBITS		Credits (e)	Balance at End of Current Quarter/Year (f)
			Account Credited (c)	Amount (d)		
1	Market to Market Short Term	87,507	175	2,771,026	2,927,951	244,432
2						
3	Idaho 1999 - NEEA (Nw energy efficiency act)	(13,040)	N/A		13,040	
4						
5	Demand Side Management Rider 29026	4,813,722	Footnote	5,620,108	6,953,227	6,146,841
6						
7	Demand Side Management Rider OR		Footnote	36,447	251,281	214,834
8						
9	BPA Credit-Residential - Idaho	1,233,436	Footnote	13,930,590	13,538,508	841,354
10						
11	BPA Credit-Residential - Oregon	40,940	Footnote	592,292	551,352	
12						
13	BPA Credit-Farm - Idaho	542,856	142	1,799,699	1,791,248	534,405
14						
15	BPA Credit-Farm - Oregon	16,130	142	68,536	69,384	16,978
16						
17	BPA Credit - Conservation	255,966	Footnote	643,506	561,206	173,666
18						
19	Pre94 Demand Side Management Order	148,607	254	156,988	8,381	
20						
21	IPUC Order 29600	13,670,833	182	9,650,000		4,020,833
22						
23	OPUC Order 04-283	100,000	182	100,000		
24						
25	Emission Sales Pre Tax		232	22,129	70,001,420	69,979,291
26						
27	Emission Sales Interest - Idaho		N/A		45,691	45,691
28						
29	Emission Sales Interest - Oregon		N/A		9,129	9,129
30						
31	Boise Operation Center	61,276	Footnote	31,970		29,306
32						
33	FERC Settlement RSV		Footnote	2,000,000	2,000,000	
34						
35	Unfunded Accumulated Deferred Income Tax	40,447,293	N/A		1,180,153	41,627,446
36						
37	Asset Retirement Obligation - Removal Cost	147,699,823	N/A		4,983,276	152,683,099
38						
39						
40						
41	TOTAL	209,105,349		37,423,291	104,885,247	276,567,305

Name of Respondent Idaho Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report 2005/Q4
FOOTNOTE DATA			

Schedule Page: 278 Line No.: 5 Column: c

142	1,532,992
154	524,824
184	1,886
232	3,246,343
254	311,477
401	2,586
	5,620,108

Schedule Page: 278 Line No.: 7 Column: c

142	1,726
154	1,077
182	2,849
232	30,779
421	15
	36,447

Schedule Page: 278 Line No.: 9 Column: c

131	4,558
142	13,926,032
	13,930,590

Schedule Page: 278 Line No.: 11 Column: c

131	100
142	592,192
	592,292

Schedule Page: 278 Line No.: 17 Column: c

154	9,883
232	627,354
254	6,247
401	22
	643,506

Schedule Page: 278 Line No.: 31 Column: c

163	320
401	21,740
402	9,911
	31,970

Schedule Page: 278 Line No.: 33 Column: c

253	1,333,333
182	666,667
	2,000,000

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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ELECTRIC OPERATING REVENUES (Account 400)

- 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.
- Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
- 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.
- 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	299,487,636	274,313,240
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	247,103,087	247,425,040
5	Large (or Ind.) (See Instr. 4)	118,259,189	111,797,200
6	(444) Public Street and Highway Lighting	2,419,886	2,300,038
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	667,269,798	635,835,518
11	(447) Sales for Resale	142,794,426	121,147,646
12	TOTAL Sales of Electricity	810,064,224	756,983,164
13	(Less) (449.1) Provision for Rate Refunds	-400,102	-1,114,364
14	TOTAL Revenues Net of Prov. for Refunds	810,464,326	758,097,528
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	5,475,745	4,214,833
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	17,912,109	18,085,801
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	15,223,771	20,423,944
22			
23			
24			
25			
26	TOTAL Other Operating Revenues	38,611,625	42,724,578
27	TOTAL Electric Operating Revenues	849,075,951	800,822,106

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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
4,760,275	4,580,337	373,602	360,462	2
				3
5,077,227	5,296,407	74,448	72,382	4
3,422,616	3,334,955	129	120	5
28,694	27,890	640	501	6
				7
				8
				9
13,288,812	13,239,589	448,819	433,465	10
2,773,852	2,885,350			11
16,062,664	16,124,939	448,819	433,465	12
				13
16,062,664	16,124,939	448,819	433,465	14

Line 12, column (b) includes \$ 4,495,436 of unbilled revenues.
Line 12, column (d) includes 48,366 MWH relating to unbilled revenues

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Name of Respondent Idaho Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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SALES OF ELECTRICITY BY RATE SCHEDULES

- 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.
- 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.
- 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.
- 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).
- For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
- 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	4,729,187	296,136,551	373,493	12,662	0.0626
3	04 - Residential - EW	562	35,844	50	11,240	0.0638
4	05 - Residential - TOD	665	43,291	59	11,271	0.0651
5	15 - Dusk to dawn lighting	2,446	444,643			0.1818
6	Unbilled Revenues	27,415	2,827,307			0.1031
7	Total 440	4,760,275	299,487,636	373,602	12,742	0.0629
8						
9	442-Commercial & Industrial Sales					
10	07 - General service	307,914	22,961,410	36,468	8,443	0.0746
11	09 - General service	3,266,464	145,132,336	18,923	172,619	0.0444
12	10 - Large power winter service					
13	84 - General Service - Net Meter					
14	15 - Dusk to dawn lighting	3,848	622,529			0.1618
15	19 - Uniform rate contracts	2,351,174	84,558,253	129	18,226,155	0.0360
16	21 - Interruptible irrigation					
17	24 - Irrigation Pumping	1,448,667	75,280,240	17,818	81,304	0.0520
18	25 - Irrigation Pumping -Time of	18,282	957,915	124	147,435	0.0524
19	40 - General service	14,332	852,898	1,115	12,854	0.0595
20	Commercial & Industrial & Unbill	1,089,162	34,996,695			0.0321
21	Total 442	8,499,843	365,362,276	74,577	113,974	0.0430
22						
23	444 - Public Street Lighting:					
24	32 - Shielded Street Lighting					
25	40 - General service	1,614	96,085	405	3,985	0.0595
26	41 - Street lighting	19,595	2,030,820	142	137,993	0.1036
27	42 - Traffic control lighting	7,485	292,981	93	80,484	0.0391
28	Total 444	28,694	2,419,886	640	44,834	0.0843
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	13,240,446	662,774,362	448,819	29,501	0.0501
42	Total Unbilled Rev.(See Instr. 6)	48,366	4,495,436	0	0	0.0929
43	TOTAL	13,288,812	667,269,798	448,819	29,608	0.0502

Name of Respondent Idaho Power Company	This Report Is:	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
	(1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		

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 not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
 RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
 LF - for long-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
 IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
 SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
 LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
 IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Raft River Rural Electric	RQ	V6-44	8.869	8.869	8.155
2	City of Weiser	RQ	V6-53	9.027	9.001	8.528
3	American Electric Power Service Cor	SF	WSPP	0.000	0.000	0.000
4	Arizona Public Service Co.	OS	WSPP	0.000	0.000	0.000
5	Arizona Public Service Co.	SF	WSPP	0.000	0.000	0.000
6	Avista Corp. - WWP Div.	OS	WSPP	0.000	0.000	0.000
7	Avista Corp. - WWP Div.	SF	WSPP	0.000	0.000	0.000
8	Avista Energy, Inc.	OS	WSPP	0.000	0.000	0.000
9	Avista Energy, Inc.	SF	WSPP	0.000	0.000	0.000
10	Benton County PUD	OS	WSPP	0.000	0.000	0.000
11	Black Hills Power Inc.	OS	WSPP	0.000	0.000	0.000
12	Black Hills Power Inc.	SF	WSPP	0.000	0.000	0.000
13	Bonneville Power Administration	OS	WSPP	0.000	0.000	0.000
14	Bonneville Power Administration	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 Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
56,093	174,071	1,188,333	3,000	1,365,404	1
51,513	526,036	1,147,277	385,755	2,059,068	2
76,400		3,857,310		3,857,310	3
4,675		417,705		417,705	4
277,424		12,675,590		12,675,590	5
50		2,200		2,200	6
1,600		136,000		136,000	7
409		18,706		18,706	8
342		12,836		12,836	9
125		4,990		4,990	10
34,738		1,303,150		1,303,150	11
14,585		502,233		502,233	12
22,428		935,265		935,265	13
25,376		1,424,760		1,424,760	14
107,606	700,107	2,335,610	388,755	3,424,472	
2,666,246	0	135,814,674	3,555,280	139,369,954	
2,773,852	700,107	138,150,284	3,944,035	142,794,426	

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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 not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
 RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
 LF - for long-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
 IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
 SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
 LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
 IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	BP Energy Company	SF	WSPP	0.000	0.000	0.000
2	Burbank, City of	OS	WSPP	0.000	0.000	0.000
3	Burbank, City of	SF	WSPP	0.000	0.000	0.000
4	Calpine Energy Services, L.P.	OS	WSPP	0.000	0.000	0.000
5	Cargill Power Markets LLC	OS	WSPP	0.000	0.000	0.000
6	Cargill Power Markets LLC	SF	WSPP	0.000	0.000	0.000
7	Chelan Co PUD	OS	WSPP	0.000	0.000	0.000
8	Chelan Co PUD	SF	WSPP	0.000	0.000	0.000
9	Clatskanie PUD	OS	WSPP	0.000	0.000	0.000
10	Clatskanie PUD	SF	WSPP	0.000	0.000	0.000
11	Colton, City of	LF	84	0.000	0.000	0.000
12	Constellation Energy Commodities Gr	OS	WSPP	0.000	0.000	0.000
13	Constellation Energy Commodities Gr	SF	WSPP	0.000	0.000	0.000
14	Coral Power, LLC	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 Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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.

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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			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
114,169		5,442,446		5,442,446	1
75		2,725		2,725	2
225		4,500		4,500	3
626		37,800		37,800	4
1,493		149,850		149,850	5
78,468		5,198,962		5,198,962	6
391		14,486		14,486	7
2,200		114,100		114,100	8
628		38,761		38,761	9
400		17,000		17,000	10
10,256		293,363		293,363	11
1,998		75,794		75,794	12
6,890		333,775		333,775	13
112,950		5,708,087		5,708,087	14
107,606	700,107	2,335,610	388,755	3,424,472	
2,666,246	0	135,814,674	3,555,280	139,369,954	
2,773,852	700,107	138,150,284	3,944,035	142,794,426	

Name of Respondent Idaho Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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).

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	EI Paso Electric Company	OS	WSPP	0.000	0.000	0.000
2	ENMAX Energy Marketing Inc.	SF	WSPP	0.000	0.000	0.000
3	Eugene Water & Electric Board	OS	WSPP	0.000	0.000	0.000
4	Eugene Water & Electric Board	SF	WSPP	0.000	0.000	0.000
5	Franklin County P.U.D.	OS	WSPP	0.000	0.000	0.000
6	Grant County P.U.D.	OS	WSPP	0.000	0.000	0.000
7	Grant County P.U.D.	SF	WSPP	0.000	0.000	0.000
8	Grays Harbor PUD	OS	WSPP	0.000	0.000	0.000
9	J. Aron & Company	SF	WSPP	0.000	0.000	0.000
10	Morgan Stanley Capital Group Inc.	OS	WSPP	0.000	0.000	0.000
11	Morgan Stanley Capital Group Inc.	SF	WSPP	0.000	0.000	0.000
12	Northern California Power Agency	SF	WSPP	0.000	0.000	0.000
13	NorthWestern Energy	IF	147	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 Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
205		16,200		16,200	1
1,200		42,000		42,000	2
710		29,480		29,480	3
12,000		514,300		514,300	4
25		350		350	5
402		19,765		19,765	6
800		39,300		39,300	7
44		968		968	8
8,200		426,650		426,650	9
2,300		113,872		113,872	10
187,737		10,024,784		10,024,784	11
5,092		380,124		380,124	12
58,617		3,554,850		3,554,850	13
			3,514,620	3,514,620	14
107,606	700,107	2,335,610	388,755	3,424,472	
2,666,246	0	135,814,674	3,555,280	139,369,954	
2,773,852	700,107	138,150,284	3,944,035	142,794,426	

Name of Respondent Idaho Power Company	This Report Is:		Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
	(1) <input checked="" type="checkbox"/> An Original	(2) <input type="checkbox"/> A Resubmission		

SALES FOR RESALE (Account 447)

- 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).
- Enter the name of the purchaser 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 purchaser.
- In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
 RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
 LF - for long-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
 IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
 SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
 LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
 IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	NorthWestern Energy	OS	WSPP	0.000	0.000	0.000
2	Pacific Northwest Generating Cooper	OS	WSPP	0.000	0.000	0.000
3	Pacific Northwest Generating Cooper	SF	WSPP	0.000	0.000	0.000
4	PacifiCorp Inc.	OS	WSPP	0.000	0.000	0.000
5	PacifiCorp Inc.	SF	T-7	0.000	0.000	0.000
6	PacifiCorp Inc.	OS	WSPP	0.000	0.000	0.000
7	PacifiCorp Inc.	SF	WSPP	0.000	0.000	0.000
8	Pinnacle West Capital Corporation	OS	WSPP	0.000	0.000	0.000
9	Pinnacle West Capital Corporation	SF	WSPP	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	Powerex Corp.	OS	WSPP	0.000	0.000	0.000
14	Powerex Corp.	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 Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
28		1,540		1,540	1
245		13,750		13,750	2
3,200		161,850		161,850	3
			38,250	38,250	4
207		13,338		13,338	5
19,606		854,164		854,164	6
114,400		6,509,135		6,509,135	7
437		40,336		40,336	8
8,800		387,450		387,450	9
			1,810	1,810	10
50,902		2,266,314		2,266,314	11
187,083		9,532,956		9,532,956	12
65,989		2,385,575		2,385,575	13
461,657		25,447,906		25,447,906	14
107,606	700,107	2,335,610	388,755	3,424,472	
2,666,246	0	135,814,674	3,555,280	139,369,954	
2,773,852	700,107	138,150,284	3,944,035	142,794,426	

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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SALES FOR RESALE (Account 447)

- 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).
- Enter the name of the purchaser 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 purchaser.
- In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
 RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
 LF - for long-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
 IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
 SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
 LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
 IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCF Demand (e)	Average Monthly CP Demand (f)
1	PPL Montana, LLC	OS	WSPP	0.000	0.000	0.000
2	PPL Montana, LLC	OS	WSPP	0.000	0.000	0.000
3	PPL Montana, LLC	SF	WSPP	0.000	0.000	0.000
4	PPM Energy, Inc.	OS	WSPP	0.000	0.000	0.000
5	PPM Energy, Inc.	SF	WSPP	0.000	0.000	0.000
6	Public Service Co. of Colorado	OS	WSPP	0.000	0.000	0.000
7	Public Service Co. of Colorado	SF	WSPP	0.000	0.000	0.000
8	Public Service Company of New Mexic	OS	WSPP	0.000	0.000	0.000
9	Public Service Company of New Mexic	SF	WSPP	0.000	0.000	0.000
10	Puget Sound Energy, Inc.	OS	WSPP	0.000	0.000	0.000
11	Puget Sound Energy, Inc.	SF	WSPP	0.000	0.000	0.000
12	Rainbow Energy Marketing Corporatio	SF	WSPP	0.000	0.000	0.000
13	Salt River Project	OS	WSPP	0.000	0.000	0.000
14	Seattle City Light	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) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
			600	600	1
4,229		150,046		150,046	2
23,960		1,235,246		1,235,246	3
840		27,853		27,853	4
51,800		2,831,500		2,831,500	5
5,208		199,224		199,224	6
23,400		1,058,890		1,058,890	7
2,015		188,425		188,425	8
1,200		65,800		65,800	9
20,047		1,055,511		1,055,511	10
5,243		325,670		325,670	11
21,625		1,043,095		1,043,095	12
710		80,080		80,080	13
10,992		738,621		738,621	14
107,606	700,107	2,335,610	388,755	3,424,472	
2,666,246	0	135,814,674	3,555,280	139,369,954	
2,773,852	700,107	138,150,284	3,944,035	142,794,426	

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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 not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.

3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows: RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW)	
					Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Seattle City Light	SF	WSPP	0.000	0.000	0.000
2	Sempra Energy Trading Corporation	OS	WSPP	0.000	0.000	0.000
3	Sempra Energy Trading Corporation	SF	WSPP	0.000	0.000	0.000
4	Snohomish County PUD	OS	WSPP	0.000	0.000	0.000
5	Snohomish County PUD	SF	WSPP	0.000	0.000	0.000
6	SUEZ Energy Marketing NA, Inc.	OS	WSPP	0.000	0.000	0.000
7	SUEZ Energy Marketing NA, Inc.	SF	WSPP	0.000	0.000	0.000
8	Tacoma Power	OS	WSPP	0.000	0.000	0.000
9	Tractebel Energy Marketing, Inc.	OS	WSPP	0.000	0.000	0.000
10	Tractebel Energy Marketing, Inc.	SF	WSPP	0.000	0.000	0.000
11	TransAlta Energy Marketing (U.S.) I	OS	WSPP	0.000	0.000	0.000
12	TransAlta Energy Marketing (U.S.) I	SF	WSPP	0.000	0.000	0.000
13	Utah Associated Municipal Power Sys	OS	WSPP	0.000	0.000	0.000
14	Utah Associated Municipal Power Sys	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 Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
7,623		536,858		536,858	1
25		1,275		1,275	2
256,319		13,614,374		13,614,374	3
6,018		281,635		281,635	4
912		66,870		66,870	5
8,534		390,713		390,713	6
90,585		4,522,270		4,522,270	7
705		38,600		38,600	8
350		15,800		15,800	9
24,000		1,084,300		1,084,300	10
16,462		637,087		637,087	11
99,625		3,778,545		3,778,545	12
4,192		286,345		286,345	13
820		60,040		60,040	14
107,606	700,107	2,335,610	388,755	3,424,472	
2,666,246	0	135,814,674	3,555,280	139,369,954	
2,773,852	700,107	138,150,284	3,944,035	142,794,426	

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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.

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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)

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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			Total (\$) (h+i+j) (k)	Line No.
	Demand Charges (\$) (h)	Energy Charges (\$) (i)	Other Charges (\$) (j)		
					1
		650		650	2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
107,606	700,107	2,335,610	388,755	3,424,472	
2,666,246	0	135,814,674	3,555,280	139,369,954	
2,773,852	700,107	138,150,284	3,944,035	142,794,426	

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Name of Respondent Idaho Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report 2005/Q4
FOOTNOTE DATA			

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

(1) Customer Charge

Schedule Page: 310 Line No.: 2 Column: j

(3) Network Transmission Charges

Schedule Page: 310.2 Line No.: 14 Column: j

(2) Capacity and Penalty Charge

Schedule Page: 310.3 Line No.: 4 Column: j

(4) Spinning or Operating Reserves

Schedule Page: 310.3 Line No.: 10 Column: j

(4) Spinning or Operating Reserves

Schedule Page: 310.4 Line No.: 1 Column: j

(4) Spinning or Operating Reserves

Name of Respondent Idaho Power Company		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/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	1,277,646	1,187,136		
5	(501) Fuel	98,982,043	98,387,370		
6	(502) Steam Expenses	6,895,514	5,333,426		
7	(503) Steam from Other Sources				
8	(Less) (504) Steam Transferred-Cr.				
9	(505) Electric Expenses	1,610,776	1,558,515		
10	(506) Miscellaneous Steam Power Expenses	6,795,112	5,868,516		
11	(507) Rents	325,176	710,713		
12	(509) Allowances				
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	115,886,267	113,045,676		
14	Maintenance				
15	(510) Maintenance Supervision and Engineering	2,130,215	2,859,869		
16	(511) Maintenance of Structures	421,603	358,798		
17	(512) Maintenance of Boiler Plant	15,855,366	12,665,232		
18	(513) Maintenance of Electric Plant	5,612,002	5,182,203		
19	(514) Maintenance of Miscellaneous Steam Plant	1,240,867	3,076,141		
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	25,260,053	24,142,243		
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	141,146,320	137,187,919		
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	4,556,943	4,421,651		
45	(536) Water for Power	4,266,568	4,016,995		
46	(537) Hydraulic Expenses	8,163,818	6,792,153		
47	(538) Electric Expenses	1,264,687	1,245,717		
48	(539) Miscellaneous Hydraulic Power Generation Expenses	1,894,576	2,528,085		
49	(540) Rents	359,290	379,919		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	20,505,882	19,384,520		

Name of Respondent Idaho Power Company		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/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)	
51	C. Hydraulic Power Generation (Continued)			
52	Maintenance			
53	(541) Maintenance Supervision and Engineering	1,275,738	1,058,293	
54	(542) Maintenance of Structures	899,749	1,004,778	
55	(543) Maintenance of Reservoirs, Dams, and Waterways	683,950	1,032,152	
56	(544) Maintenance of Electric Plant	2,466,384	2,268,044	
57	(545) Maintenance of Miscellaneous Hydraulic Plant	2,854,670	2,642,221	
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	8,180,491	8,005,488	
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	28,686,373	27,390,008	
60	D. Other Power Generation			
61	Operation			
62	(546) Operation Supervision and Engineering	390,680	391,835	
63	(547) Fuel	4,181,468	4,874,063	
64	(548) Generation Expenses	231,162	170,854	
65	(549) Miscellaneous Other Power Generation Expenses	342,401	298,934	
66	(550) Rents			
67	TOTAL Operation (Enter Total of lines 62 thru 66)	5,145,711	5,735,686	
68	Maintenance			
69	(551) Maintenance Supervision and Engineering	194	230	
70	(552) Maintenance of Structures	255,394	123,893	
71	(553) Maintenance of Generating and Electric Plant	30,292	69,240	
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	428,740	240,994	
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	714,620	434,357	
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	5,860,331	6,170,043	
75	E. Other Power Supply Expenses			
76	(555) Purchased Power	222,310,315	195,642,193	
77	(556) System Control and Load Dispatching	77,483	106,362	
78	(557) Other Expenses	-1,023,410	41,082,749	
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	221,364,388	236,831,304	
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	397,057,412	407,579,274	
81	2. TRANSMISSION EXPENSES			
82	Operation			
83	(560) Operation Supervision and Engineering	2,013,395	2,031,371	
84	(561) Load Dispatching	2,971,942	2,909,482	
85	(562) Station Expenses	1,591,008	1,686,223	
86	(563) Overhead Lines Expenses	515,152	544,172	
87	(564) Underground Lines Expenses			
88	(565) Transmission of Electricity by Others	7,657,106	8,441,863	
89	(566) Miscellaneous Transmission Expenses	297,608	17,854	
90	(567) Rents	1,565,610	2,176,624	
91	TOTAL Operation (Enter Total of lines 83 thru 90)	16,611,821	17,807,589	
92	Maintenance			
93	(568) Maintenance Supervision and Engineering	695,940	653,160	
94	(569) Maintenance of Structures	68,184		
95	(570) Maintenance of Station Equipment	2,688,845	3,009,973	
96	(571) Maintenance of Overhead Lines	1,908,500	2,356,489	
97	(572) Maintenance of Underground Lines			
98	(573) Maintenance of Miscellaneous Transmission Plant	16,446	7,878	
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	5,377,915	6,027,500	
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	21,989,736	23,835,089	
101	3. DISTRIBUTION EXPENSES			
102	Operation			
103	(580) Operation Supervision and Engineering	3,845,031	3,608,681	

Name of Respondent Idaho Power Company		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/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)	
104	3. DISTRIBUTION Expenses (Continued)			
105	(581) Load Dispatching	2,536,857	2,395,937	
106	(582) Station Expenses	945,089	950,120	
107	(583) Overhead Line Expenses	2,967,382	3,481,870	
108	(584) Underground Line Expenses	1,733,935	1,670,619	
109	(585) Street Lighting and Signal System Expenses	120,630	151,313	
110	(586) Meter Expenses	4,108,887	4,127,933	
111	(587) Customer Installations Expenses	773,447	545,521	
112	(588) Miscellaneous Expenses	4,603,412	4,997,634	
113	(589) Rents	157,873	150,421	
114	TOTAL Operation (Enter Total of lines 103 thru 113)	21,792,543	22,080,049	
115	Maintenance			
116	(590) Maintenance Supervision and Engineering	91,162	66,616	
117	(591) Maintenance of Structures	69,106		
118	(592) Maintenance of Station Equipment	2,629,976	2,932,915	
119	(593) Maintenance of Overhead Lines	10,928,110	11,137,680	
120	(594) Maintenance of Underground Lines	1,109,939	1,245,264	
121	(595) Maintenance of Line Transformers	321,335	259,850	
122	(596) Maintenance of Street Lighting and Signal Systems	378,751	494,696	
123	(597) Maintenance of Meters	773,149	953,983	
124	(598) Maintenance of Miscellaneous Distribution Plant	230,529	178,232	
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	16,532,057	17,269,236	
126	TOTAL Distribution Exp (Enter Total of lines 114 and 125)	38,324,600	39,349,285	
127	4. CUSTOMER ACCOUNTS EXPENSES			
128	Operation			
129	(901) Supervision	494,549	426,782	
130	(902) Meter Reading Expenses	4,723,518	4,724,432	
131	(903) Customer Records and Collection Expenses	9,292,260	9,290,028	
132	(904) Uncollectible Accounts	1,556,140	3,009,866	
133	(905) Miscellaneous Customer Accounts Expenses	28,055	-6,051	
134	TOTAL Customer Accounts Expenses (Total of lines 129 thru 133)	16,094,522	17,445,057	
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES			
136	Operation			
137	(907) Supervision	281,012	313,453	
138	(908) Customer Assistance Expenses	8,575,566	7,346,134	
139	(909) Informational and Instructional Expenses		5,525	
140	(910) Miscellaneous Customer Service and Informational Expenses	763,679	732,850	
141	TOTAL Cust. Service and Information. Exp. (Total lines 137 thru 140)	9,620,257	8,397,962	
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	40,438,326	45,232,476	
152	(921) Office Supplies and Expenses	16,117,873	14,719,947	
153	(Less) (922) Administrative Expenses Transferred-Credit	23,657,334	26,358,321	

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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)
154	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
155	(923) Outside Services Employed	7,823,980	7,056,785
156	(924) Property Insurance	2,866,971	3,207,907
157	(925) Injuries and Damages	5,711,625	5,996,017
158	(926) Employee Pensions and Benefits	22,956,720	26,676,544
159	(927) Franchise Requirements	2,300	2,075
160	(928) Regulatory Commission Expenses	4,009,949	3,976,930
161	(929) (Less) Duplicate Charges-Cr.		
162	(930.1) General Advertising Expenses	120,381	118,315
163	(930.2) Miscellaneous General Expenses	1,856,141	1,959,515
164	(931) Rents	3,800	12,291
165	TOTAL Operation (Enter Total of lines 151 thru 164)	78,250,732	82,600,481
166	Maintenance		
167	(935) Maintenance of General Plant	3,473,712	2,525,892
168	TOTAL Admin & General Expenses (Total of lines 165 thru 167)	81,724,444	85,126,373
169	TOTAL Elec Op and Maint Expn (Tot 80, 100, 126, 134, 141, 148, 168)	564,810,971	581,733,040

Name of Respondent Idaho Power Company	This Report Is:		Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
	(1) <input checked="" type="checkbox"/> An Original	(2) <input type="checkbox"/> A Resubmission		

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

- 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.
- 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.
- 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	COGENERATION AND SMALL POWER					
2	Willis and Betty Deveny	LU	-			
3	James B. Howell/CHI	LU	-			
4	Tamarack Energy Partnership	LU	-	4.942	-1	-1
5	Owyhee Irrigation District					
6	Mitchell Butte	LU	-			
7	Owyhee Dam	LU	-			
8	Tunnel #1	LU	-			
9	Reynolds Irrigation District	LU	-			
10	Clifton E. Jenson	LU	-	.05	-1	-1
11	Snake River Pottery	LU	-			
12	White Water Ranch	LU	-			
13	John R LeMoyne	LU	-			
14	David R Snedigar	LU	-			
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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 monthly (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
794				50,199		50,199	2
4,048				267,172		267,172	3
41,580			1,576,498	1,214,688		2,791,186	4
							5
5,724				447,089		447,089	6
19,039				1,313,265		1,313,265	7
17,497				1,898,906		1,898,906	8
1,203				83,264		83,264	9
277			17,500	4,759		22,259	10
385				24,685		24,685	11
561				35,967		35,967	12
647				35,142		35,142	13
1,151				76,136		76,136	14
3,918,389	110,013	327,466	2,815,124	219,383,501	111,690	222,310,315	

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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**PURCHASED POWER (Account 555)
(Including power exchanges)**

- 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.
- 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.
- 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	Mud Creek Hydro, Inc	LU	-			
2	Rim View Trout Company	OS	-			
3	Curry Cattle Company	LU	-	.084	-1	-1
4	Branchflower Company	LU	-			
5	Big Wood Canal Company					
6	Black Canyon	LU	-			
7	Jim Knight	LU	-			
8	Sagebrush	LU	-			
9	Fisheries Development	OS	-			
10	Shorock Hydro Inc.					
11	Shoshone Csp	LU	-			
12	Shoshone #2	LU	-			
13	Rock Creek #1 Joint Venture	LU	-	1.732	-1	-1
14	Richard Kaster					
	Total					

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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 monthly (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)	
328				20,242		20,242	1
1,228				58,925		58,925	2
564			26,796	9,699		36,495	3
845				56,209		56,209	4
							5
337				22,358		22,358	6
1,111				77,844		77,844	7
944				66,833		66,833	8
1,047				49,192		49,192	9
							10
1,890				128,691		128,691	11
1,786				118,419		118,419	12
8,772			552,508	150,784		703,292	13
							14
3,918,389	110,013	327,466	2,815,124	219,383,501	111,690	222,310,315	

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of <u>2005/Q4</u>
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**PURCHASED POWER (Account 555)
(Including power exchanges)**

- 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.
- 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.
- 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	Box Canyon	LU	-			
2	Briggs Creek	LU	-			
3	David McCollum	LU	-			
4	H.K. Hydro / Mud Creek S & S	LU	-			
5	Allan/Vernon Ravenscroft	LU	-	.488	-1	-1
6	William Arkoosh	LU	-			
7	Clear Springs Food Inc.	LU	-			
8	Koyle Hydro Inc.	LU	-			
9	Kasel & Witherspoon	LU	-			
10	Lateral 10 Ventures	LU	-			
11	Crystal Springs Hydro	LU	-			
12	Pigeon Cove Power	LU	-	1,389	-1	-1
13	Consolidated Hydro Inc. / Enel		-			
14	GeoBon #2	LU	-			
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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 monthly (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)	
1,736				109,464		109,464	1
3,628				233,761		233,761	2
732				34,176		34,176	3
1,282				78,622		78,622	4
1,519			155,672	26,103		181,775	5
2,985				218,840		218,840	6
3,541				259,155		259,155	7
2,971				209,383		209,383	8
3,608				237,143		237,143	9
8,017				509,903		509,903	10
7,469				480,860		480,860	11
7,382			486,150	110,259		596,409	12
							13
2,659				195,735		195,735	14
3,918,389	110,013	327,466	2,815,124	219,383,501	111,690	222,310,315	

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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	Barber Dam	LU	-			
2	Rock Creek #2	LU	-			
3	Dietrich Drop	LU	-			
4	Lowline #2	LU	-			
5	Cedar Draw/Little Mac Power Co.	LU	-			
6	South Forks Joint Venture (5)	LU	-			
7	Little Wood River Irrigation Dis	LU	-			
8	Marco Rancher's Irrigation Inc.	LU	-			
9	Faulkner Brothers Hydro Inc.	LU	-			
10	Magic Reservoir Hydro	LU	-			
11	Bypass Limited	LU	-			
12	SE Hazelton A LP	LU	-			
13	Jerry L. McMillan	OS	-			
14	Lemhi HydroPower Company	LU	-			
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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 monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
9,841				484,064		484,064	1
6,315				292,705		292,705	2
12,310				665,294		665,294	3
8,349				431,492		431,492	4
5,202				326,203		326,203	5
22,856				1,601,292		1,601,292	6
6,276				447,463		447,463	7
2,018				130,306		130,306	8
2,797				210,575		210,575	9
12,180				662,652		662,652	10
23,232				1,203,545		1,203,545	11
19,840				983,206		983,206	12
118				5,649		5,649	13
1,255				90,763		90,763	14
3,918,389	110,013	327,466	2,815,124	219,383,501	111,690	222,310,315	

Name of Respondent Idaho Power Company	This Report Is:		Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
	(1) <input checked="" type="checkbox"/> An Original	(2) <input type="checkbox"/> A Resubmission		

**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	J R Simplot Co.	LU	-			
2	Blind Canyon Hydro	LU	-			
3	City of Hailey	LU	-			
4	City of Pocatello	LU	-			
5	Marysville Hydro Partners	LU	-			
6	Wilson Power Company	LU	-			
7	Hazleton Power Company	LU	-			
8	Pristine Springs Inc.	LU	-			
9	Vaagen Brothers Lumber Inc.	LU	-			
10	Horseshoe Bend Hydro	LU	-			
11	Contractors Power Group Inc.	LU	-			
12	Rupert Cogeneration Partners	LU	-			
13	Glenns Ferry Cogeneration Partne	LU	-			
14	Lewandowski Farms	OS	-			
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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 monthly (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)	
61,670				2,825,175		2,825,175	1
3,493				251,486		251,486	2
				2		2	3
1,310				91,226		91,226	4
44,955				2,633,915		2,633,915	5
22,224				1,475,109		1,475,109	6
19,654				1,303,536		1,303,536	7
891				42,998		42,998	8
22,819				1,378,832		1,378,832	9
33,299				2,223,983		2,223,983	10
3,921				259,374		259,374	11
81,879				4,898,573		4,898,573	12
74,783				4,433,000		4,433,000	13
237				10,219		10,219	14
3,918,389	110,013	327,466	2,815,124	219,383,501	111,690	222,310,315	

Name of Respondent Idaho Power Company	This Report Is:		Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
	(1) <input checked="" type="checkbox"/> An Original	(2) <input type="checkbox"/> A Resubmission		

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

- 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.
- 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.
- 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	Tasco - Nampa	OS	-			
2	Tasco - Twin Falls	OS	-			
3	Pristine Springs Inc #3	OS	-			
4	Ted S. Sorenson/Tiber Dam	LU	-			
5	Fossil Gulch Wind	OS	-			
6	OTHER PURCHASED POWER					
7	American Electric Power Service	SF	WSPP			
8	Anaheim City of	OS	WSPP			
9	Arizona Public Service Co	OS	WSPP			
10	Arizona Public Service Co.	SF	WSPP			
11	Arizona Public Service Co	AD	WSPP			
12	Avista Corp - WWP Div.	OS	WSPP			
13	Avista Corp. - WWP Div.	SF	T-12			
14	Avista Corp. - WWP Div	SF	T-10			
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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 monthly (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)	
1,837				84,858		84,858	1
242				14,690		14,690	2
1,412				64,358		64,358	3
30,702				1,345,267		1,345,267	4
18,004				726,247		726,247	5
							6
68,000				4,210,680		4,210,680	7
147				6,333		6,333	8
4,648				140,560		140,560	9
34,475				1,491,012		1,491,012	10
					-1,350	-1,350	11
21,740				1,202,600		1,202,600	12
25				1,207		1,207	13
					14,925	14,925	14
3,918,389	110,013	327,466	2,815,124	219,383,501	111,690	222,310,315	

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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**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	Avista Corp. - WWP Div.	SF	WSPP			
2	Avista Energy, Inc.	OS	WSPP			
3	Avista Energy, Inc.	SF	WSPP			
4	Benton County PUD	OS	WSPP			
5	Benton County PUD	SF	WSPP			
6	Black Hills Power Inc.	OS	WSPP			
7	Black Hills Power Inc.	OS	WSPP			
8	Black Hills Power Inc.	OS	WSPP			
9	Black Hills Power Inc.	SF	WSPP			
10	Bonneville Power Administration	OS	WSPP			
11	Bonneville Power Administration	SF	WSPP			
12	Bonneville Power Administration	SF	WSPP			
13	BP Energy Company	SF	WSPP			
14	Calpine Energy Services, L.P.	OS	WSPP			
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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 monthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.

6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.

7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.

8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges (\$) (j)	Energy Charges (\$) (k)	Other Charges (\$) (l)	Total (j+k+l) of Settlement (\$) (m)	
2,340				188,300		188,300	1
9,823				488,728		488,728	2
9,415				759,618		759,618	3
845				39,335		39,335	4
1,800				121,400		121,400	5
56				3,280		3,280	6
32,768				1,823,720		1,823,720	7
800				42,200		42,200	8
1,000				87,400		87,400	9
53,951				4,000,378		4,000,378	10
224				11,323		11,323	11
209,475				9,455,153		9,455,153	12
115,550				5,984,078		5,984,078	13
6,600				312,109		312,109	14
3,918,389	110,013	327,466	2,815,124	219,383,501	111,690	222,310,315	

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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	Calpine Energy Services, L.P.	SF	WSPP			
2	Cargill Power Markets LLC	OS	WSPP			
3	Cargill Power Markets LLC	OS	WSPP			
4	Cargill Power Markets LLC	SF	WSPP			
5	Chelan Co PUD	SF	WSPP			
6	Chelan Co PUD	SF	WSPP			
7	Clatskanie PUD	OS	WSPP			
8	Clatskanie PUD	SF	WSPP			
9	Constellation Energy Commodities	OS	WSPP			
10	Constellation Energy Commodities	SF	WSPP			
11	Coral Power, LLC	SF	WSPP			
12	Douglas County PUD	OS	WSPP			
13	Douglas County PUD	SF	WSPP			
14	Douglas County PUD	SF	WSPP			
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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 monthly (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)	
4,000				186,500		186,500	1
2,351				67,770		67,770	2
60				3,000		3,000	3
46,910				3,526,545		3,526,545	4
4				229		229	5
3,600				235,200		235,200	6
595				14,830		14,830	7
515				43,755		43,755	8
942				69,951		69,951	9
13,800				1,170,800		1,170,800	10
296,806				14,173,720		14,173,720	11
81				2,025		2,025	12
2				117		117	13
1,000				63,500		63,500	14
3,918,389	110,013	327,466	2,815,124	219,383,501	111,690	222,310,315	

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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**PURCHASED POWER (Account 555)
(Including power exchanges)**

- 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.
- 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.
- 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	El Paso Electric Company	SF	WSPP			
2	Eugene Water & Electric Board	OS	WSPP			
3	Eugene Water & Electric Board	SF	WSPP			
4	Franklin County P.U.D.	OS	WSPP			
5	Franklin County P.U.D.	SF	WSPP			
6	Grant County P.U.D.	OS	WSPP			
7	Grant County P.U.D.	SF	WSPP			
8	Grant County P.U.D.	SF	WSPP			
9	Grays Harbor PUD	OS	WSPP			
10	Grays Harbor PUD	SF	WSPP			
11	J. Aron & Company	SF	WSPP			
12	Morgan Stanley Capital Group Inc	OS	WSPP			
13	Morgan Stanley Capital Group Inc	SF	WSPP			
14	Nevada Power Company	OS	WSPP			
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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 monthly (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)	
8,800				883,900		883,900	1
460				32,728		32,728	2
2,790				182,940		182,940	3
205				9,250		9,250	4
800				64,800		64,800	5
2,510				100,610		100,610	6
5				262		262	7
1,729				143,540		143,540	8
525				22,423		22,423	9
800				45,200		45,200	10
60,600				3,237,390		3,237,390	11
3,616				313,459		313,459	12
474,655				25,399,649		25,399,649	13
2,275				138,275		138,275	14
3,918,389	110,013	327,466	2,815,124	219,383,501	111,690	222,310,315	

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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**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	NorthWestern Energy, L.L.C.	OS	WSPP			
2	NorthWestern Energy, L.L.C.	SF	T-7			
3	NorthWestern Energy, L.L.C.	SF	WSPP			
4	NorthWestern Energy, L.L.C.	LF	V6-51			
5	Pacific Northwest Generating Coo	OS	WSPP			
6	Pacific Northwest Generating Coo	SF	WSPP			
7	PacifiCorp Inc.	OS	WSPP			
8	PacifiCorp Inc.	SF	T-13			
9	PacifiCorp Inc.	SF	T-13			
10	PacifiCorp Inc.	SF	WSPP			
11	PacifiCorp Inc.	SF	WSPP			
12	Pinnacle West Capital Corp	SF	WSPP			
13	Portland General Electric Company	OS	WSPP			
14	Portland General Electric Company	SF	T-14			
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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 monthly (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)	
1,284				65,220		65,220	1
27				1,304		1,304	2
5,715				282,825		282,825	3
54,052				2,973,445		2,973,445	4
65				1,560		1,560	5
400				29,200		29,200	6
89,949				5,354,971		5,354,971	7
138				6,711		6,711	8
					3,850	3,850	9
					900	900	10
120,803				8,864,115		8,864,115	11
85,775				7,146,125		7,146,125	12
29,133				1,942,949		1,942,949	13
31				1,532		1,532	14
3,918,389	110,013	327,466	2,815,124	219,383,501	111,690	222,310,315	

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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	Portland General Electric Company	SF	WSPP			
2	Powerex Corp.	OS	WSPP			
3	Powerex Corp.	SF	WSPP			
4	PPL Montana, LLC	LF	WSPP			
5	PPL Montana, LLC	OS	WSPP			
6	PPL Montana, LLC	OS	WSPP			
7	PPL Montana, LLC	OS	WSPP			
8	PPL Montana, LLC	SF	WSPP			
9	PPM Energy, Inc.	OS	WSPP			
10	PPM Energy, Inc.	SF	WSPP			
11	Public Service Co. of Colorado	OS	WSPP			
12	Public Service Co. of Colorado	SF	WSPP			
13	Public Service Company of New Mexico	OS	WSPP			
14	Public Service Company of New Mexico	SF	WSPP			
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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 monthly (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)	
61,688				3,007,205		3,007,205	1
9,598				921,784		921,784	2
65,139				3,984,415		3,984,415	3
103,584				4,609,488		4,609,488	4
23,909				1,481,693		1,481,693	5
400				17,600		17,600	6
90				7,740		7,740	7
111,276				6,344,930		6,344,930	8
22,652				1,241,500		1,241,500	9
102,451				6,764,424		6,764,424	10
169				5,776		5,776	11
46,800				2,820,450		2,820,450	12
505				19,965		19,965	13
7,121				673,303		673,303	14
3,918,389	110,013	327,466	2,815,124	219,383,501	111,690	222,310,315	

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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**PURCHASED POWER (Account 555)
(Including power exchanges)**

- 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.
- 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.
- 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	Puget Sound Energy, Inc.	OS	WSPP			
2	Puget Sound Energy, Inc.	SF	WSPP			
3	Rainbow Energy Marketing Corpora	OS	WSPP			
4	Rainbow Energy Marketing Corpora	SF	WSPP			
5	Salt River Project	OS	WSPP			
6	Salt River Project	SF	WSPP			
7	Seattle City Light	OS	WSPP			
8	Seattle City Light	SF	WSPP			
9	Seattle City Light	SF	WSPP			
10	Sempra Energy Solutions	SF	WSPP			
11	Sempra Energy Trading Corporatio	OS	WSPP			
12	Sempra Energy Trading Corporatio	SF	WSPP			
13	Sierra Pacific Power Company	OS	WSPP			
14	Sierra Pacific Power Company	SF	55			
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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 monthly (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)	
8,827				586,335		586,335	1
4,790				355,810		355,810	2
1,079				69,324		69,324	3
14,000				762,860		762,860	4
2,175				192,690		192,690	5
605				43,525		43,525	6
5,889				272,800		272,800	7
7				346		346	8
3,450				206,100		206,100	9
1,200				87,400		87,400	10
49				2,622		2,622	11
446,775				23,201,693		23,201,693	12
1,325				125,425		125,425	13
21				1,009		1,009	14
3,918,389	110,013	327,466	2,815,124	219,383,501	111,690	222,310,315	

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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	Sierra Pacific Power Company	SF	WSPP			
2	Snohomish County PUD	OS	WSPP			
3	Snohomish County PUD	SF	WSPP			
4	SUEZ Energy Marketing NA, Inc.	OS	WSPP			
5	SUEZ Energy Marketing NA, Inc.	SF	WSPP			
6	Tacoma Power	OS	WSPP			
7	Tacoma Power	SF	WSPP			
8	Tacoma Power	SF	WSPP			
9	Tractebel Energy Marketing, Inc.	OS	WSPP			
10	Tractebel Energy Marketing, Inc.	SF	WSPP			
11	TransAlta Energy Marketing (U.S.	OS	WSPP			
12	TransAlta Energy Marketing (U.S.	SF	WSPP			
13	Tunock Irrigation District	OS	WSPP			
14	Tunock Irrigation District	OS	WSPP			
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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 monthly (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)	
					850	850	1
7,117				359,369		359,369	2
27,337				1,369,765		1,369,765	3
2,369				184,210		184,210	4
20,600				1,128,350		1,128,350	5
7,071				390,225		390,225	6
2				117		117	7
12,387				653,772		653,772	8
702				30,744		30,744	9
12,000				626,000		626,000	10
6,499				448,179		448,179	11
169,528				8,678,935		8,678,935	12
52				2,240		2,240	13
400				18,200		18,200	14
3,918,389	110,013	327,466	2,815,124	219,383,501	111,690	222,310,315	

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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**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	Utah Associated Municipal Power	OS	WSPP			
2	POWER EXCHANGES					
3	Anaheim, City of	EX	WSPP			
4	Avista Energy Inc	EX	WSPP			
5	Puget Sound Energy, Inc.	EX	T-9			
6	Sierra Pacific Power Company	EX	WSPP			
7	Bonneville Power Administration	EX	-			
8	NorthWestern Energy, LLC	EX	-			
9	PacificCorp Inc	EX	-			
10	Sierra Pacific Power Company	EX	-			
11	OTHER TRANSACTIONS					
12	City of Exchange					
13	Mountain Power Plant Test Power					
14						
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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 monthly (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)	
53				1,515		1,515	1
							2
	18,600	43,200					3
	800	800					4
	41	41					5
	2,672	2,672					6
	47,854	9,456					7
		8,457					8
	40,046	249,065					9
		13,775					10
							11
					-502,000	-502,000	12
					594,515	594,515	13
							14
3,918,389	110,013	327,466	2,815,124	219,383,501	111,690	222,310,315	

Name of Respondent Idaho Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report 2005/Q4
FOOTNOTE DATA			

Schedule Page: 326 Line No.: 4 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.: 2 Column: a
Non Firm Purchases
Schedule Page: 326.1 Line No.: 9 Column: a
Non Firm Purchases
Schedule Page: 326.3 Line No.: 13 Column: a
Non Firm Purchases
Schedule Page: 326.4 Line No.: 5 Column: a
Ida-West, a subsidiary of IdaCorp, has partial ownership of these projects.
Schedule Page: 326.4 Line No.: 6 Column: a
Ida-West, a subsidiary of IdaCorp, has partial ownership of these projects.
Schedule Page: 326.4 Line No.: 7 Column: a
Ida-West a subsidiary of IdaCorp has partial ownership of these projects.
Schedule Page: 326.4 Line No.: 14 Column: a
Non Firm Purchases
Schedule Page: 326.5 Line No.: 1 Column: a
Non Firm Purchases
Schedule Page: 326.5 Line No.: 2 Column: a
Non Firm Purchases
Schedule Page: 326.5 Line No.: 3 Column: a
Non Firm Purchases
Schedule Page: 326.5 Line No.: 5 Column: a
Non Firm Purchases
Schedule Page: 326.5 Line No.: 8 Column: a
Non Firm Purchases
Schedule Page: 326.5 Line No.: 9 Column: a
Non Firm Purchases
Schedule Page: 326.5 Line No.: 11 Column: a
2004 Price adjustment
Schedule Page: 326.5 Line No.: 12 Column: a
Non Firm Purchases
Schedule Page: 326.5 Line No.: 14 Column: a
Spinning or Operating Reserves
Schedule Page: 326.6 Line No.: 2 Column: a
Non Firm Purchases
Schedule Page: 326.6 Line No.: 4 Column: a
Non Firm Purchases
Schedule Page: 326.6 Line No.: 6 Column: a
Non Firm Purchases
Schedule Page: 326.6 Line No.: 7 Column: a
Non Firm Purchases
Schedule Page: 326.6 Line No.: 8 Column: a
Non Firm Purchases
Schedule Page: 326.6 Line No.: 10 Column: a
Non Firm Purchases
Schedule Page: 326.6 Line No.: 14 Column: a
Non Firm Purchases
Schedule Page: 326.7 Line No.: 2 Column: a
Non Firm Purchases
Schedule Page: 326.7 Line No.: 3 Column: a
Non Firm Purchases

Name of Respondent Idaho Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report 2005/Q4
FOOTNOTE DATA			

Schedule Page: 326.7	Line No.: 7	Column: a	Non Firm Purchases
Schedule Page: 326.7	Line No.: 9	Column: a	Non Firm Purchases
Schedule Page: 326.7	Line No.: 12	Column: a	Non Firm Purchases
Schedule Page: 326.8	Line No.: 2	Column: a	Non Firm Purchases
Schedule Page: 326.8	Line No.: 4	Column: a	Non Firm Purchases
Schedule Page: 326.8	Line No.: 6	Column: a	Non Firm Purchases
Schedule Page: 326.8	Line No.: 9	Column: a	Non Firm Purchases
Schedule Page: 326.8	Line No.: 12	Column: a	Non Firm Purchases
Schedule Page: 326.8	Line No.: 14	Column: a	Non Firm Purchases
Schedule Page: 326.9	Line No.: 1	Column: a	Non Firm Purchases
Schedule Page: 326.9	Line No.: 5	Column: a	Non Firm Purchases
Schedule Page: 326.9	Line No.: 7	Column: a	Non Firm Purchases
Schedule Page: 326.9	Line No.: 9	Column: a	Spinning or Operating Reserves
Schedule Page: 326.9	Line No.: 10	Column: a	Spinning or Operating Reserves
Schedule Page: 326.9	Line No.: 13	Column: a	Non Firm Purchases
Schedule Page: 326.10	Line No.: 2	Column: a	Non Firm Purchases
Schedule Page: 326.10	Line No.: 5	Column: a	Non Firm Purchases
Schedule Page: 326.10	Line No.: 6	Column: a	Non Firm Purchases
Schedule Page: 326.10	Line No.: 7	Column: a	Non Firm Purchases
Schedule Page: 326.10	Line No.: 9	Column: a	Non Firm Purchases
Schedule Page: 326.10	Line No.: 11	Column: a	Non Firm Purchases
Schedule Page: 326.10	Line No.: 13	Column: a	Non Firm Purchases
Schedule Page: 326.11	Line No.: 1	Column: a	Non Firm Purchases
Schedule Page: 326.11	Line No.: 3	Column: a	Non Firm Purchases
Schedule Page: 326.11	Line No.: 5	Column: a	Non Firm Purchases
Schedule Page: 326.11	Line No.: 7	Column: a	Non Firm Purchases
Schedule Page: 326.11	Line No.: 11	Column: a	Non Firm Purchases
Schedule Page: 326.11	Line No.: 13	Column: a	Non Firm Purchases

Name of Respondent Idaho Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report 2005/Q4
FOOTNOTE DATA			

Non Firm Purchases

Schedule Page: 326.12 Line No.: 1 Column: a

Spinning or Operating Reserves

Schedule Page: 326.12 Line No.: 2 Column: a

Non Firm Purchases

Schedule Page: 326.12 Line No.: 4 Column: a

Non Firm Purchases

Schedule Page: 326.12 Line No.: 6 Column: a

Non Firm Purchases

Schedule Page: 326.12 Line No.: 9 Column: a

Non Firm Purchases

Schedule Page: 326.12 Line No.: 11 Column: a

Non Firm Purchases

Schedule Page: 326.12 Line No.: 13 Column: a

Non Firm Purchases

Schedule Page: 326.12 Line No.: 14 Column: a

Non Firm Purchases

Schedule Page: 326.13 Line No.: 1 Column: a

Non Firm Purchases

Schedule Page: 326.13 Line No.: 7 Column: a

Scheduled losses not removed with loss transactions.

Schedule Page: 326.13 Line No.: 8 Column: a

Scheduled losses not removed with loss transactions.

Schedule Page: 326.13 Line No.: 9 Column: a

Scheduled losses not removed with loss transactions.

Schedule Page: 326.13 Line No.: 10 Column: a

Scheduled losses not removed with loss transactions.

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Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)
(including transactions referred to as 'wheeling')

- 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.
- Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
- 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)
- In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Bonneville Power Administration - OTEC	Bonneville Power Administration	Oregon Trails Electric Co-op	FNO
2	Bonneville Power Administration - US	Bonneville Power Administration	United States Bureau of Reclamati	FNO
3	Bonneville Power Administration - Ra	Bonneville Power Administration	Raft River Electric Co-op	FNO
4	Bonneville Power Administration - PF	Bonneville Power Administration	Priority Firm Customers	FNO
5	Bonneville Power Administration - W	Bonneville Power Administration	Vigilante	OLF
6	Milner Irrigation District	United States Bureau of Reclamat	Milner Irrigation District	OLF
7	City of Seattle	Seattle City Light	Bonneville Power Administration	OLF
8	PacifiCorp	PacifiCorp West	PacifiCorp West	FNO
9	United States Bureau of Indian Affairs	Bonneville Power Administration	United States Bureau of Indian Af	OLF
10	PacifiCorp Power Marketing	PacifiCorp West	PacifiCorp West	OLF
11	PacifiCorp Power Marketing	PacifiCorp West	PacifiCorp West	OLF
12	PacifiCorp Power Marketing	PacifiCorp East	PacifiCorp West	OLF
13	Arizona Public Service	PacifiCorp East	Avista	LFP
14	Arizona Public Service	PacifiCorp East	Sierra Pacific Power	NF
15	Arizona Public Service	Idaho Power Company	PacifiCorp East	NF
16	Aron - Goldman Sachs	PacifiCorp East	Bonneville Power Administration	NF
17	Aron - Goldman Sachs	PacifiCorp East	Sierra Pacific Power	NF
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred to as 'wheeling')

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
5				258,035	258,035	1
5				174,246	174,246	2
5				181,992	181,992	3
5				723,046	723,046	4
5	Bannack Tap	Vigilante Electric C	4			5
Legacy	Minidoka, Idaho	Various in Idaho	1	1,885	1,885	6
Legacy	LYPK	LGBP				7
5			1	2,125	2,125	8
Legacy	LaGrande, Oregon	Various in Idaho	11	13,475	13,475	9
Legacy (414)	JBSN	ENPR		214,127	214,127	10
Legacy (440)	JBSN	ENPR		19,726	19,726	11
Legacy (433)	BOBR	JBSN		162,623	162,623	12
5	BOBR	LOLO		4,000	4,000	13
5	BOBR	M345		78,182	78,182	14
5	IPCO	BOBR		800	800	15
5	BOBR	LGBP		27	27	16
5	BOBR	M345		518	518	17
			17	4,775,766	4,775,766	

Name of Respondent Idaho Power Company		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission		Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Including transactions referred to as 'wheeling')					
<p>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.</p> <p>2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).</p> <p>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)</p> <p>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.</p>					
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	Aron - Goldman Sachs	NorthWestern/ PacifiCorp East	PacifiCorp East	NF	
2	Aron - Goldman Sachs	NorthWestern/ PacifiCorp East	Sierra Pacific Power	NF	
3	Aron - Goldman Sachs	Bonneville Power Administration	PacifiCorp East	NF	
4	Aron - Goldman Sachs	Bonneville Power Administration	Sierra Pacific Power	NF	
5	Aron - Goldman Sachs	Avista	Sierra Pacific Power	NF	
6	Avista Energy, Inc.	Bonneville Power Administration	Sierra Pacific Power	NF	
7	Black Hills Power	PacifiCorp West	Sierra Pacific Power	NF	
8	Bonneville Power Administration	Bonneville Power Administration	Sierra Pacific Power	NF	
9	Bonneville Power Administration	Avista	Sierra Pacific Power	NF	
10	Cargill Power Markets	PacifiCorp East	PacifiCorp West	NF	
11	Cargill Power Markets	PacifiCorp East	Sierra Pacific Power	NF	
12	Cargill Power Markets	PacifiCorp West	PacifiCorp East	NF	
13	Cargill Power Markets	PacifiCorp West	PacifiCorp West	NF	
14	Cargill Power Markets	PacifiCorp West	Sierra Pacific Power	NF	
15	Cargill Power Markets	NorthWestern/ PacifiCorp East	PacifiCorp East	NF	
16	Cargill Power Markets	NorthWestern/ PacifiCorp East	Sierra Pacific Power	NF	
17	Cargill Power Markets	PacifiCorp West	PacifiCorp East	NF	
TOTAL					

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred to as 'wheeling')

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
5	HTSP	BOBR		169	169	1
5	HTSP	M345		150	150	2
5	LGBP	BOBR		75	75	3
5	LGBP	M345		3,635	3,635	4
5	LOLO	M345		221	221	5
5	LGBP	M345		12	12	6
5	JBSN	M345		34	34	7
5	LGBP	M345		820	820	8
5	LOLO	M345		299	299	9
5	BOBR	ENPR		7,276	7,276	10
5	BOBR	M345		400	400	11
5	ENPR	BOBR		18,944	18,944	12
5	ENPR	JBSN		5,647	5,647	13
5	ENPR	M345		70,720	70,720	14
5	HTSP	BOBR		9,247	9,247	15
5	HTSP	M345		3,695	3,695	16
5	JBSN	BOBR		23,327	23,327	17
			17	4,775,766	4,775,766	

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)
(Including transactions referred to as 'wheeling')

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Cargill Power Markets	PacifiCorp West	PacifiCorp West	NF
2	Cargill Power Markets	PacifiCorp West	Bonneville Power Administration	NF
3	Cargill Power Markets	PacifiCorp West	Sierra Pacific Power	NF
4	Cargill Power Markets	Bonneville Power Administration	PacifiCorp East	NF
5	Cargill Power Markets	Bonneville Power Administration	PacifiCorp West	NF
6	Cargill Power Markets	Bonneville Power Administration	Sierra Pacific Power	NF
7	Cargill Power Markets	Avista	Sierra Pacific Power	NF
8	Cargill Power Markets	Sierra Pacific Power	Bonneville Power Administration	NF
9	Morgan Stanley Capital Group	PacifiCorp East	Bonneville Power Administration	NF
10	Morgan Stanley Capital Group	PacifiCorp East	Sierra Pacific Power	NF
11	Morgan Stanley Capital Group	PacifiCorp West	Sierra Pacific Power	NF
12	Morgan Stanley Capital Group	NorthWestern/ PacifiCorp East	PacifiCorp East	NF
13	Morgan Stanley Capital Group	NorthWestern/ PacifiCorp East	Sierra Pacific Power	NF
14	Morgan Stanley Capital Group	NorthWestern/ PacifiCorp East	PacifiCorp East	NF
15	Morgan Stanley Capital Group	Bonneville Power Administration	PacifiCorp East	NF
16	Morgan Stanley Capital Group	Bonneville Power Administration	Sierra Pacific Power	NF
17	Morgan Stanley Capital Group	Avista	PacifiCorp East	NF
TOTAL				

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred to as 'wheeling')

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
5	JBSN	ENPR		2,247	2,247	1
5	JBSN	LGBP		90,867	90,867	2
5	JBSN	M345		33,154	33,154	3
5	LGBP	BOBR		3,994	3,994	4
5	LGBP	JBSN		24	24	5
5	LGBP	M345		39,603	39,603	6
5	LOLO	M345		555	555	7
5	M345	LGBP		1,283	1,283	8
5	BOBR	LGBP		2,009	2,009	9
5	BOBR	M345		4,536	4,536	10
5	ENPR	M345		400	400	11
5	HTSP	BOBR		18,219	18,219	12
5	HTSP	M345		2,383	2,383	13
5	JEFF	BOBR		168	168	14
5	LGBP	BOBR		3,154	3,154	15
5	LGBP	M345		2,119	2,119	16
5	LOLO	BOBR		914	914	17
			17	4,775,766	4,775,766	

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of <u>2005/Q4</u>
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)
(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	Morgan Stanley Capital Group	Avista	Sierra Pacific Power	NF
2	Morgan Stanley Capital Group	Seattle City Light/Idaho Power C	Bonneville Power Administration	NF
3	Morgan Stanley Capital Group	Seattle City Light/Idaho Power C	Sierra Pacific Power	NF
4	Pacificorp Power Marketing	PacifiCorp East	PacifiCorp West	NF
5	Pacificorp Power Marketing	PacifiCorp East	NorthWestern/ PacifiCorp East	NF
6	Pacificorp Power Marketing	PacifiCorp East	PacifiCorp West	NF
7	Pacificorp Power Marketing	PacifiCorp West	PacifiCorp East	NF
8	Pacificorp Power Marketing	PacifiCorp West	Sierra Pacific Power	NF
9	Pacificorp Power Marketing	NorthWestern/ PacifiCorp East	PacifiCorp East	NF
10	Pacificorp Power Marketing	PacifiCorp West	PacifiCorp East	NF
11	Pacificorp Power Marketing	PacifiCorp West	Sierra Pacific Power	NF
12	Portland General Electric	PacifiCorp East	Bonneville Power Administration	NF
13	Portland General Electric	PacifiCorp West	PacifiCorp East	NF
14	Portland General Electric	NorthWestern/ PacifiCorp East	PacifiCorp East	NF
15	Portland General Electric	NorthWestern/ PacifiCorp East	Bonneville Power Administration	NF
16	Portland General Electric	NorthWestern/ PacifiCorp East	Bonneville Power Administration	NF
17	Portland General Electric	NorthWestern/ PacifiCorp East	PacifiCorp East	NF
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred to as 'wheeling')

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
5	LOLO	M345		581	581	1
5	LYPK	LGBP		80	80	2
5	LYPK	M345		256	256	3
5	BOBR	ENPR		51,915	51,915	4
5	BOBR	HTSP		339	339	5
5	BOBR	M500		8,662	8,662	6
5	ENPR	BOBR		170,760	170,760	7
5	ENPR	M345		12,147	12,147	8
5	HTSP	BOBR		170	170	9
5	JBSN	BOBR		11,931	11,931	10
5	JBSN	M345		77,565	77,565	11
5	BOBR	LGBP		585	585	12
5	ENPR	BOBR		30	30	13
5	HTSP	BOBR		6,678	6,678	14
5	HTSP	LGBP		263	263	15
5	JEFF	LGBP		1,132	1,132	16
5	MLCK	BOBR		720	720	17
			17	4,775,766	4,775,766	

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)
(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 Corporation	PacifiCorp East	PacifiCorp West	NF
2	Powerex Corporation	PacifiCorp East	NorthWestern/ PacifiCorp East	NF
3	Powerex Corporation	PacifiCorp East	Bonneville Power Administration	NF
4	Powerex Corporation	PacifiCorp East	Avista	NF
5	Powerex Corporation	PacifiCorp East	Sierra Pacific Power	NF
6	Powerex Corporation	PacifiCorp West	PacifiCorp East	NF
7	Powerex Corporation	PacifiCorp West	PacifiCorp West	NF
8	Powerex Corporation	PacifiCorp West	Sierra Pacific Power	NF
9	Powerex Corporation	NorthWestern/ PacifiCorp East	PacifiCorp East	NF
10	Powerex Corporation	NorthWestern/ PacifiCorp East	Bonneville Power Administration	NF
11	Powerex Corporation	NorthWestern/ PacifiCorp East	Sierra Pacific Power	NF
12	Powerex Corporation	Idaho Power Company	PacifiCorp East	NF
13	Powerex Corporation	PacifiCorp West	PacifiCorp East	NF
14	Powerex Corporation	PacifiCorp West	PacifiCorp West	NF
15	Powerex Corporation	PacifiCorp West	NorthWestern/ PacifiCorp East	NF
16	Powerex Corporation	PacifiCorp West	Bonneville Power Administration	NF
17	Powerex Corporation	PacifiCorp West	Sierra Pacific Power	NF
TOTAL				

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred to as 'wheeling')

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
5	BOBR	ENPR		1,782	1,782	1
5	BOBR	HTSP		2,015	2,015	2
5	BOBR	LGBP		102,327	102,327	3
5	BOBR	LOLO		4,373	4,373	4
5	BOBR	M345		8,416	8,416	5
5	ENPR	BOBR		68,481	68,481	6
5	ENPR	JBSN		177	177	7
5	ENPR	M345		42,039	42,039	8
5	HTSP	BOBR		7,790	7,790	9
5	HTSP	LGBP		1,133	1,133	10
5	HTSP	M345		858	858	11
5	IPCO	BOBR		837	837	12
5	JBSN	BOBR		10,309	10,309	13
5	JBSN	ENPR		5	5	14
5	JBSN	HTSP		393	393	15
5	JBSN	LGBP		110,270	110,270	16
5	JBSN	M345		198	198	17
			17	4,775,766	4,775,766	

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)
(Including transactions referred to as 'wheeling')

- 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.
- Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
- 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)
- 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 Corporation	NorthWestern/ PacifiCorp East	Bonneville Power Administration	NF
2	Powerex Corporation	Bonneville Power Administration	PacifiCorp East	NF
3	Powerex Corporation	Bonneville Power Administration	PacifiCorp West	NF
4	Powerex Corporation	Bonneville Power Administration	Sierra Pacific Power	NF
5	Powerex Corporation	Avista	PacifiCorp East	NF
6	Powerex Corporation	Avista	Bonneville Power Administration	NF
7	Powerex Corporation	Avista	Sierra Pacific Power	NF
8	Powerex Corporation	Sierra Pacific Power	PacifiCorp East	NF
9	Powerex Corporation	Sierra Pacific Power	Bonneville Power Administration	NF
10	PP & L Montana	PacifiCorp West	NorthWestern/ PacifiCorp East	NF
11	PP & L Montana	NorthWestern/ PacifiCorp East	PacifiCorp East	NF
12	PP & L Montana	NorthWestern/ PacifiCorp East	Bonneville Power Administration	NF
13	PP & L Montana	PacifiCorp West	NorthWestern/ PacifiCorp East	NF
14	PP & L Montana	PacifiCorp West	Bonneville Power Administration	NF
15	PP & L Montana	PacifiCorp West	NorthWestern/ PacifiCorp East	NF
16	PP & L Montana	NorthWestern/ PacifiCorp East	PacifiCorp East	NF
17	PP & L Montana	NorthWestern/ PacifiCorp East	PacifiCorp East	NF
TOTAL				

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred to as 'wheeling')

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
5	JEFF	LGBP		365	365	1
5	LGBP	BOBR		26,947	26,947	2
5	LGBP	JBSN		6,870	6,870	3
5	LGBP	M345		94,946	94,946	4
5	LOLO	BOBR		578	578	5
5	LOLO	LGBP		60	60	6
5	LOLO	M345		10,606	10,606	7
5	M345	BOBR		228	228	8
5	M345	LGBP		16,249	16,249	9
5	ENPR	HTSP		70	70	10
5	HTSP	BOBR		36,981	36,981	11
5	HTSP	LGBP		65	65	12
5	JBSN	HTSP		20	20	13
5	JBSN	LGBP		27	27	14
5	JBSN	MLCK		125	125	15
5	JEFF	BOBR		12	12	16
5	JEFF	BOBR		1,842	1,842	17
			17	4,775,766	4,775,766	

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)
(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	PP & L Montana	NorthWestern/ PacifiCorp East	Bonneville Power Administration	NF
2	PP & L Montana	NorthWestern/ PacifiCorp East	Avista	NF
3	PP & L Montana	Bonneville Power Administration	Sierra Pacific Power	NF
4	PP & L Montana	Sierra Pacific Power	PacifiCorp East	NF
5	PP & L Montana	Sierra Pacific Power	Bonneville Power Administration	NF
6	PP & L Montana	NorthWestern/ PacifiCorp East	Bonneville Power Administration	NF
7	PPM Energy	PacifiCorp East	PacifiCorp West	NF
8	PPM Energy	PacifiCorp East	Bonneville Power Administration	NF
9	PPM Energy	PacifiCorp East	Sierra Pacific Power	NF
10	PPM Energy	NorthWestern/ PacifiCorp East	Sierra Pacific Power	NF
11	PPM Energy	Bonneville Power Administration	PacifiCorp East	NF
12	PPM Energy	Bonneville Power Administration	Sierra Pacific Power	NF
13	Public Service of Colorado	Bonneville Power Administration	PacifiCorp West	NF
14	Puget Sound Energy	NorthWestern/ PacifiCorp East	PacifiCorp East	NF
15	Puget Sound Energy	NorthWestern/ PacifiCorp East	Bonneville Power Administration	NF
16	Puget Sound Energy	NorthWestern/ PacifiCorp East	Avista	NF
17	Puget Sound Energy	Avista	Bonneville Power Administration	NF
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred to as 'wheeling')

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
5	JEFF	LGBP		1,304	1,304	1
5	JEFF	LOLO		60	60	2
5	LGBP	M345		73	73	3
5	M345	BOBR		100	100	4
5	M345	LGBP		650	650	5
5	MLCK	LGBP		206	206	6
5	BOBR	ENPR		58	58	7
5	BOBR	LGBP		60,541	60,541	8
5	BOBR	M345		485	485	9
5	HTSP	M345		272	272	10
5	LGBP	BOBR		1,793	1,793	11
5	LGBP	M345		272	272	12
5	LGBP	JBSN		75	75	13
5	HTSP	BOBR		7,042	7,042	14
5	HTSP	LGBP		1,671	1,671	15
5	HTSP	LOLO		512	512	16
5	LOLO	LGBP		1,024	1,024	17
			17	4,775,766	4,775,766	

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)
(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	Puget Sound Energy	Sierra Pacific Power	Bonneville Power Administration	NF
2	Rainbow Energy Marketing Company	NorthWestern/ PacifiCorp East	PacifiCorp East	NF
3	Rainbow Energy Marketing Company	PacifiCorp West	Bonneville Power Administration	NF
4	Sierra Pacific Power	PacifiCorp East	Sierra Pacific Power	NF
5	Sierra Pacific Power	PacifiCorp West	PacifiCorp East	NF
6	Sierra Pacific Power	PacifiCorp West	Sierra Pacific Power	NF
7	Sierra Pacific Power	NorthWestern/ PacifiCorp East	PacifiCorp East	NF
8	Sierra Pacific Power	NorthWestern/ PacifiCorp East	Sierra Pacific Power	NF
9	Sierra Pacific Power	Idaho Power Company	PacifiCorp West	NF
10	Sierra Pacific Power	Idaho Power Company	Bonneville Power Administration	NF
11	Sierra Pacific Power	Idaho Power Company	Avista	NF
12	Sierra Pacific Power	PacifiCorp West	PacifiCorp East	NF
13	Sierra Pacific Power	PacifiCorp West	Bonneville Power Administration	NF
14	Sierra Pacific Power	PacifiCorp West	Sierra Pacific Power	NF
15	Sierra Pacific Power	NorthWestern/ PacifiCorp East	PacifiCorp East	NF
16	Sierra Pacific Power	NorthWestern/ PacifiCorp East	Sierra Pacific Power	NF
17	Sierra Pacific Power	Bonneville Power Administration	PacifiCorp East	NF
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred to as 'wheeling')

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
5	M345	LGBP		779	779	1
5	HTSP	BOBR		1,605	1,605	2
5	JBSN	LGBP		400	400	3
5	BOBR	M345		17,437	17,437	4
5	ENPR	BOBR		23,112	23,112	5
5	ENPR	M345		159,884	159,884	6
5	HTSP	BOBR		146,214	146,214	7
5	HTSP	M345		21,531	21,531	8
5	IPCO	ENPR		600	600	9
5	IPCO	LGBP		2,450	2,450	10
5	IPCO	LOLO		5,265	5,265	11
5	JBSN	BOBR		400	400	12
5	JBSN	LGBP		800	800	13
5	JBSN	M345		40,821	40,821	14
5	JEFF	BOBR		45	45	15
5	JEFF	M345		349,667	349,667	16
5	LGBP	BOBR		120	120	17
			17	4,775,766	4,775,766	

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)
(Including transactions referred to as 'wheeling')

- 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.
- Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
- 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)
- In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Sierra Pacific Power	Bonneville Power Administration	Sierra Pacific Power	NF
2	Sierra Pacific Power	Avista	Sierra Pacific Power	NF
3	Sierra Pacific Power	Seattle City Light/Idaho Power C	Sierra Pacific Power	NF
4	Sierra Pacific Power	Sierra Pacific Power	PacifiCorp East	NF
5	Sierra Pacific Power	Sierra Pacific Power	NorthWestern/ PacifiCorp East	NF
6	Sierra Pacific Power	Sierra Pacific Power	Bonneville Power Administration	NF
7	TransAlta Energy Marketing	NorthWestern/ PacifiCorp East	Sierra Pacific Power	NF
8	TransAlta Energy Marketing	Bonneville Power Administration	Sierra Pacific Power	NF
9	TransAlta Energy Marketing	Sierra Pacific Power	Bonneville Power Administration	NF
10				
11				
12				
13				
14				
15				
16				
17				
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions referred to as 'wheeling')

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Substation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
5	LGBP	M345		170,793	170,793	1
5	LOLO	M345		434,917	434,917	2
5	LYPK	M345		225,976	225,976	3
5	M345	BOBR		455	455	4
5	M345	HTSP		876	876	5
5	M345	LGBP		9,003	9,003	6
5	HTSP	M345		106	106	7
5	LGBP	M345		7	7	8
5	M345	LGBP		50	50	9
						10
						11
						12
						13
						14
						15
						16
						17
			17	4,775,766	4,775,766	

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions referred 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.
633,086	-621,992		11,094	1
776,593	-300,027		476,566	2
343,830	-296,165		47,665	3
1,380,161	-1,305,052		75,109	4
15,000			15,000	5
	11,060		11,060	6
		4,860	4,860	7
4,164	6,440		10,604	8
54,169			54,169	9
	320,478		320,478	10
	37,754		37,754	11
	333,264		333,264	12
	28,934		28,934	13
	565,523		565,523	14
	5,787		5,787	15
	109		109	16
	2,087		2,087	17
3,207,003	11,598,124	4,860	14,809,987	

Name of Respondent Idaho Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions referred 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.
	681		681	1
	604		604	2
	302		302	3
	14,647		14,647	4
	891		891	5
	84		84	6
	81		81	7
	2,883		2,883	8
	1,051		1,051	9
	33,559		33,559	10
	1,845		1,845	11
	87,374		87,374	12
	26,045		26,045	13
	326,177		326,177	14
	42,649		42,649	15
	17,042		17,042	16
	107,590		107,590	17
3,207,003	11,598,124	4,860	14,809,987	

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions referred 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.
	10,364		10,364	1
	419,100		419,100	2
	152,914		152,914	3
	18,421		18,421	4
	111		111	5
	182,658		182,658	6
	2,560		2,560	7
	5,918		5,918	8
	7,943		7,943	9
	17,933		17,933	10
	1,581		1,581	11
	72,028		72,028	12
	9,421		9,421	13
	664		664	14
	12,469		12,469	15
	8,377		8,377	16
	3,613		3,613	17
3,207,003	11,598,124	4,860	14,809,987	

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions referred to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.

10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.

11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges (\$) (k)	Energy Charges (\$) (l)	(Other Charges) (\$) (m)	Total Revenues (\$) (k+l+m) (n)	Line No.
	2,297		2,297	1
	316		316	2
	1,012		1,012	3
	233,723		233,723	4
	1,526		1,526	5
	38,997		38,997	6
	768,766		768,766	7
	54,686		54,686	8
	765		765	9
	53,714		53,714	10
	349,200		349,200	11
	3,245		3,245	12
	166		166	13
	37,048		37,048	14
	1,459		1,459	15
	6,280		6,280	16
	3,994		3,994	17
3,207,003	11,598,124	4,860	14,809,987	

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions referred 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.
	9,507		9,507	1
	10,750		10,750	2
	545,908		545,908	3
	23,330		23,330	4
	44,899		44,899	5
	365,342		365,342	6
	944		944	7
	224,276		224,276	8
	41,559		41,559	9
	6,044		6,044	10
	4,577		4,577	11
	4,465		4,465	12
	54,998		54,998	13
	27		27	14
	2,097		2,097	15
	588,284		588,284	16
	1,056		1,056	17
3,207,003	11,598,124	4,860	14,809,987	

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions referred 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.
	1,947		1,947	1
	143,761		143,761	2
	36,651		36,651	3
	506,531		506,531	4
	3,084		3,084	5
	320		320	6
	56,582		56,582	7
	1,216		1,216	8
	86,687		86,687	9
	275		275	10
	145,429		145,429	11
	256		256	12
	79		79	13
	106		106	14
	492		492	15
	47		47	16
	7,244		7,244	17
3,207,003	11,598,124	4,860	14,809,987	

Name of Respondent Idaho Power Company	This Report Is:		Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
	(1) <input checked="" type="checkbox"/> An Original	(2) <input type="checkbox"/> A Resubmission		

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions referred 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.
	5,128		5,128	1
	236		236	2
	287		287	3
	393		393	4
	2,556		2,556	5
	810		810	6
	255		255	7
	266,166		266,166	8
	2,132		2,132	9
	1,196		1,196	10
	7,883		7,883	11
	1,196		1,196	12
	254		254	13
	31,056		31,056	14
	7,369		7,369	15
	2,258		2,258	16
	4,516		4,516	17
3,207,003	11,598,124	4,860	14,809,987	

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions referred to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.

10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.

11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges (\$) (k)	Energy Charges (\$) (l)	(Other Charges) (\$) (m)	Total Revenues (\$) (k+l+m) (n)	Line No.
	3,435		3,435	1
	6,787		6,787	2
	1,691		1,691	3
	69,265		69,265	4
	91,808		91,808	5
	635,107		635,107	6
	580,806		580,806	7
	85,528		85,528	8
	2,383		2,383	9
	9,732		9,732	10
	20,914		20,914	11
	1,589		1,589	12
	3,178		3,178	13
	162,153		162,153	14
	179		179	15
	1,388,982		1,388,982	16
	477		477	17
3,207,003	11,598,124	4,860	14,809,987	

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions referred 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.
	678,441		678,441	1
	1,727,620		1,727,620	2
	897,644		897,644	3
	1,807		1,807	4
	3,480		3,480	5
	35,763		35,763	6
	1,249		1,249	7
	82		82	8
	589		589	9
				10
				11
				12
				13
				14
				15
				16
				17
3,207,003	11,598,124	4,860	14,809,987	

Name of Respondent Idaho Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report 2005/Q4
FOOTNOTE DATA			

Schedule Page: 328 Line No.: 1 Column: h

Line 1 - 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

Line 2 - 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.: 3 Column: h

Line 3 - 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.: 4 Column: h

Line 2 - 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.: 5 Column: a

Line 5 - The agreement between Idaho Power and the Bonneville Power Administration expires September 30, 2016.

Schedule Page: 328 Line No.: 6 Column: a

Line 6 - The contract between Idaho Power and the Milner Irrigation District will automatically renewed on December 31, 2004 for a five year term unless either party provides prior notice.

Schedule Page: 328 Line No.: 7 Column: a

Line 7 - The agreement between Idaho Power and the City of Seattle expires December 31, 2007. Contract demand for 2005 is zero.

Schedule Page: 328 Line No.: 7 Column: m

Monthly customer charge.

Schedule Page: 328 Line No.: 8 Column: a

Line 8 - The contract between Idaho Power and PacifiCorp - Imnaha expires on September 30, 2010.

Schedule Page: 328 Line No.: 9 Column: a

Line 9 - 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.: 10 Column: a

Line 10, 11 and 12 - 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.: 11 Column: a

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.: 12 Column: a

Line 10, 11 and 12 - 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.

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

- 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.
- 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.
- 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.
- Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
- 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.
- Enter "TOTAL" in column (a) as the last line.
- Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Megawatt-hours Received (c)	Megawatt-hours Delivered (d)	Demand Charges (\$) (e)	Energy Charges (\$) (f)	Other Charges (\$) (g)	Total Cost of Transmission (\$) (h)
1	Delivered Power to Whlr							
2								
3	Bonneville Power Admin	LFP	141,759	141,759	331,190			331,190
4	Northwestern Energy	NF	11,494	11,494		53,562		53,562
5	Okanogan County	NF	224	224		448		448
6	PPL Montana LLC	SFP	-19,008	-19,008		-47,520		-47,520
7	Seattle City Light	NF	11,616	11,616		27,664		27,664
8								
9								
10	Received Power from Whl							
11								
12	Avista Corp WWP Div	NF	53,842	53,842		285,293		285,293
13	Avista Corp WWP Div	SFP	248,797	248,797		1,233,030		1,233,030
14	Benton County PUD	NF	1,008	1,008		2,108		2,108
15	Bonneville Power Admin	NF	27,068	27,068		128,071		128,071
16	Bonneville Power Admin	LFP	366,569	366,569	796,762			796,762
	TOTAL		1,683,311	1,683,311	1,331,952	6,321,469	3,685	7,657,106

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges (\$) (e)	Energy Charges (\$) (f)	Other Charges (\$) (g)	Total Cost of Transmission (\$) (h)
1	Clatskanie PUD	NF	592	592		1,588		1,588
2	Grays Harbor PUD	NF	200	200		350		350
3	Northwestern Energy LLC	SFP	12,440	12,440		41,861		41,861
4	Northwestern Energy LLC	LFP	103,567	103,567	204,000	14,138		218,138
5	Okanogan County PUD	NF	2,891	2,891		5,782		5,782
6	PacifiCorp Inc	NF	47,383	47,383		452,924		452,924
7	PacifiCorp Inc	SFP	233,950	233,950		2,714,185		2,714,185
8	Portland General Elect	NF	11,952	11,952		27,596		27,596
9	PPL Montana, LLC	SFP	125,670	125,670		673,200		673,200
10	Seattle City Light	NF	62,422	62,422		164,402		164,402
11	Sierra Pacific Power Co	NF	4,760	4,760		8,732		8,732
12	Snohomish County PUD	NF	197,870	197,870		447,754		447,754
13	Tacoma Power	NF	36,245	36,245		86,301		86,301
14	Other						3,685	3,685
15								
16								
	TOTAL		1,683,311	1,683,311	1,331,952	6,321,469	3,685	7,657,106

Name of Respondent Idaho Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report 2005/Q4
FOOTNOTE DATA			

Schedule Page: 332 Line No.: 3 Column: a

(1) Bonneville Power Administration LFP 9/30/2016

Schedule Page: 332 Line No.: 6 Column: a

Idaho Power sold transmission back to PPL Montana LLC after Idaho Power previously purchased transmission.

Schedule Page: 332 Line No.: 16 Column: a

(2) Bonneville Power Administration LFP 7/25/2011

Schedule Page: 332.1 Line No.: 4 Column: a

(3) Northwest Energy, L.L.C. LFP Contract can be terminated at anytime, with 30 days prior notice

Name of Respondent Idaho Power Company		This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)				
Line No.	Description (a)	Amount (b)		
1	Industry Association Dues	315,826		
2	Nuclear Power Research Expenses			
3	Other Experimental and General Research Expenses			
4	Pub & Dist Info to Stkhdrs...expn servicing outstanding Securities	215,647		
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < \$5,000	725,836		
6	Rothford Barker	25,171		
7	Jack Lemley	15,833		
8	Jon Miller	42,000		
9	Gary Michael	30,625		
10	Peter O'Neill	28,000		
11	Richard Reiten	22,297		
12	Thomas Wilford	22,500		
13	Robert Tintsman	27,500		
14	Christopher Culp	835		
15	Joan Smith	19,458		
16				
17	Chambers of Commerce & Other Civic Organizations	79,106		
18				
19	Memberships:			
20	Associated Taxpayers of Idaho	21,252		
21	Corporate Executive Board	20,000		
22	Idaho Assoc of Commerce and Industry	9,400		
23	Idaho Assoc of Counties	1,700		
24	Idaho Mining Association	2,500		
25	National Association of Investors	4,000		
26	National Hydropower Assoc	21,182		
27	Pacific Northwest Utilities	35,559		
28	The Conference Board	2,500		
29	University of Idaho	10,500		
30	Utility Wind Interest Group	5,000		
31	West Associates	22,580		
32	Western Energy Institute	20,000		
33	Wyoming Taxpayers Assoc	2,635		
34				
35	Miscellaneous General Management:			
36	Moody's Investor Service	7,750		
37	New York Stock Exchange	13,867		
38	Pacific Stock Exchange	1,782		
39	Standard & Poor's	83,300		
40				
41				
42				
43				
44				
45				
46	TOTAL	1,856,141		

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of acquisition 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			8,573,690		8,573,690
2	Steam Production Plant	23,062,474				23,062,474
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	12,558,923		447		12,559,370
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	2,598,425				2,598,425
7	Transmission Plant	12,490,634				12,490,634
8	Distribution Plant	26,576,747				26,576,747
9	General Plant	15,942,426				15,942,426
10	Common Plant-Electric	-296,299				-296,299
11	TOTAL	92,933,330		8,574,137		101,507,467

B. Basis for Amortization Charges

Account 404

	Balance to be Amortized	2005 Amortization	Balance to be amortized 12/31/05	Remaining months of amortization 12/31/05
(1)	8,992	8,992	-	-
(2)	36,000	12,000	24,000	24
(3)	8,443,567	361,293	12,659,523	-
(4)	20,179,079	8,035,506	18,007,166	-
(5)	247,082	12,252	234,830	230
(6)		144,094	6,340,123	264
TOTAL	28,914,720	8,574,137	37,265,642	

- (1) T E Roach development archaeological study, FERC & Oregon license costs (termination date July 31, 2005).
- (2) Shoshone-Bannock Tribe license and use agreement (termination date December 31, 2023).
- (3) Middle snake relicensing costs (amortized over a 30-year liscense period).
- (4) Computer software packages (amortized over a 60 month period from date of purchase).

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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	310.00	203	75.00		2.27	R4.0	19.20
13	311.00	130,393	90.00	-10.00	2.59	S1.0	18.30
14	312.10	79,045	55.00	-10.00	2.76	R3.0	19.10
15	312.20	410,593	70.00	-10.00	2.89	R1.5	18.10
16	312.30	3,917	25.00	20.00	2.77	R3.0	16.40
17	314.00	122,505	50.00	-10.00	3.46	S0.5	17.20
18	315.00	61,130	65.00		2.16	S1.5	17.80
19	316.00	11,156	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	116	9.00	25.00	8.45	L3.0	3.50
23	316.70	251	17.00	25.00	4.26	S2.5	8.10
24	316.80	1,135	14.00	35.00	7.01	L0.5	9.40
25	317.000	3,633					
26	Subtotal Steam	824,362					
27	331.00	129,998	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	218,938	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	185,688	80.00	-5.00	1.83	R3.0	38.00
32	334.00	36,429	47.00		2.85	R1.5	28.00
33	335.00	14,852	100.00		1.86	S0.0	34.90
34	336.00	6,950	75.00		1.95	R3.0	34.70
35	Subtotal Hydro	617,915					
36	341.00	5,339	35.00		2.84	SQUARE	34.50
37	342.00	3,519	35.00		2.83	SQUARE	33.90
38	343.00	29,370	35.00		2.88	SQUARE	34.50
39	344.00	60,940	35.00		2.84	SQUARE	34.50
40	345.00	4,680	35.00		2.79	SQUARE	34.50
41	346.00	1,342	35.00		2.88	SQUARE	34.50
42	Subtotal Other	105,190					
43	350.20	22,097	65.00		1.54	R3.0	52.30
44	350.21	3,529	24.00		4.09	SQUARE	24.00
45	352.00	33,135	60.00	-20.00	1.29	R3.0	48.00
46	353.00	235,849	45.00	-5.00	2.12	S0.5	32.70
47	354.00	79,295	60.00	-30.00	2.45	S4.0	37.30
48	355.00	92,201	55.00	-60.00	2.94	R2.0	39.90
49	356.00	114,776	60.00	-20.00	1.96	R2.0	41.40
50	359.00	318	65.00		1.07	R3.0	27.00

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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	581,200					
13	361.00	19,894	55.00	-20.00	2.05	R2.5	40.70
14	362.00	138,465	50.00		1.64	O1.0	43.60
15	364.00	190,455	41.00	-50.00	3.67	R1.5	29.80
16	365.00	96,250	46.00	-30.00	3.25	R2.0	29.50
17	366.00	41,611	60.00	-25.00	2.04	R2.0	51.90
18	367.00	153,861	37.00	-10.00	2.73	S1.5	28.60
19	368.00	293,686	35.00	5.00	1.73	R2.0	27.10
20	369.00	48,560	30.00	-30.00	3.69	S2.0	20.50
21	370.00	50,389	30.00		4.06	L2.0	19.70
22	371.10	359	8.00		28.42	S5.0	2.30
23	371.20	2,201	11.00	-20.00	11.85	R0.5	7.00
24	373.00	4,001	20.00	-20.00	5.75	R1.0	10.90
25	Subtotal Distribution	1,039,732					
26	390.11	25,798	100.00	-5.00	2.27	S1.5	38.50
27	390.12	28,388	50.00	-5.00	2.17	R3.0	36.00
28	390.20	7,192	25.00		3.85	S3.0	16.90
29	391.10	11,261	20.00		9.66	SQUARE	7.70
30	391.20	18,826	5.00		20.00	SQUARE	5.00
31	391.201	14,709	5.00		34.48	SQUARE	1.70
32	391.21	2,764	6.00		16.67	S5.0	6.00
33	391.211	2,063	6.00		31.98	S5.0	2.00
34	392.10	293	9.00	25.00	1.78	L3.0	7.90
35	392.30	2,580	15.00	50.00	3.79	S2.0	15.00
36	392.40	16,359	9.00	25.00	3.45	L3.0	6.90
37	392.50	518	9.00	25.00	9.45	L3.0	9.00
38	392.60	20,613	17.00	25.00	4.72	S2.5	10.20
39	392.70	3,853	17.00	25.00	4.26	S2.5	7.90
40	392.90	3,314	30.00	25.00	1.93	S1.0	21.90
41	393.00	974	25.00		7.89	SQUARE	8.70
42	394.00	4,208	20.00		8.31	SQUARE	8.10
43	395.00	9,260	20.00		6.53	SQUARE	9.80
44	396.00	7,263	14.00	35.00	6.90	L0.5	7.70
45	397.10	8,648	15.00		11.61	SQUARE	5.70
46	397.20	13,230	15.00		9.99	SQUARE	7.40
47	397.30	2,879	15.00		9.99	SQUARE	6.70
48	397.40	1,334	10.00		16.45	SQUARE	5.20
49	398.00	2,623	15.00		8.50	SQUARE	8.80
50	Subtotal General	208,950					

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of <u>2005/Q4</u>
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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	Total Plant	3,377,349					
13							
14							
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Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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REGULATORY COMMISSION EXPENSES

- 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.
- 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 administrative charges	3,570,833		3,570,833	
3					
4					
5	Regulatory Commission Expenses - Idaho				
6	Intervenor Funding (various cases)		17,500	17,500	
7	Lost Revenue Appeal IPC-E-01-34		4,400	4,400	
8	General Rate Case 2005		141,236	141,236	
9	Emission Allowance		37,369	37,369	
10	Other Expenses		39	39	
11					
12	Oregon Hydro - Fees Amortization	158,506		158,506	
13					
14	Regulatory Commission Expenses - Oregon				
15	General Rate Case		61,718	61,718	
16	Other Expenses		18,348	18,348	
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	3,729,339	280,610	4,009,949	

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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				Line No.
CURRENTLY CHARGED TO			Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	
Department (f)	Account No. (g)	Amount (h)					
							1
electric	928	3,570,833					2
							3
							4
							5
electric	928	17,500					6
electric	928	4,400					7
electric	928	141,236					8
electric	928	37,369					9
electric	928	39					10
							11
electric	928	158,506					12
							13
							14
electric	928	61,718					15
electric	928	18,348					16
							17
							18
							19
							20
							21
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							45
		4,009,949					46

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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:

- | | | |
|--|---|---|
| <p>A. Electric R, D & D Performed Internally:</p> <p>(1) Generation</p> <p> a. hydroelectric</p> <p> i. Recreation fish and wildlife</p> <p> ii Other hydroelectric</p> <p> b. Fossil-fuel steam</p> <p> c. Internal combustion or gas turbine</p> <p> d. Nuclear</p> <p> e. Unconventional generation</p> <p> f. Siting and heat rejection</p> | <p>(3) Transmission</p> <p> a. Overhead</p> <p> b. Underground</p> <p>(4) Distribution</p> <p>(5) Environment (other than equipment)</p> <p>(6) Other (Classify and include items in excess of \$5,000.)</p> <p>(7) Total Cost Incurred</p> | <p>B. Electric, R, D & D Performed Externally:</p> <p>(1) Research Support to the electrical Research Council or the Electric Power Research Institute</p> |
|--|---|---|

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		Energy Star Northwest Homes
5		Oregon Residential Weather Sch 78
6		Residential Education Initiative
7		Savings with a Twist
8		Weatherization Assistance for Qualified Customers
9		Commercial Building Efficiency Program
10		Commercial Education Initiative
11		Oregon Commercial Audit Sch 82
12		Oregon School Efficiency
13		School Operator Training
14		Industrial Efficiency
15		Irrigation Efficiency
16		Irrigation Efficiency Rewards Program
17		Irrigation Peak Clipping
18		Distribution Efficiency Initiative
19		EEAG Meetings
20		NEEA
21		Other Conservation & Renewable Discounts
22		Small Project/Education funds
23		DSM Analysis & Accounting
24		
25	(7)	
26	B. 4 Research Support to Others	BPA Energy House Calls
27		BPA Rebate Advantage
28		
29		
30		
31		
32		
33		
34		
35	Total R, D&D	
36		
37		

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

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

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing \$5,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under \$5,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.

4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)

5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.

6. If costs have not been segregated for R, D & D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."

7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
					1
					2
754,062			754,062		3
253,105			253,105		4
612			612		5
8,110			8,110		6
73,152			73,152		7
1,502,759			1,502,759		8
194,066			194,066		9
3,497			3,497		10
5,450			5,450		11
86			86		12
1,750			1,750		13
1,128,076			1,128,076		14
119,696			119,696		15
30,881			30,881		16
1,468,281			1,468,281		17
21,552			21,552		18
1,191			1,191		19
476,891			476,891		20
103,786			103,786		21
14,896			14,896		22
162,504			162,504		23
					24
					25
	375,733		375,733		26
	46,299		46,299		27
					28
					29
					30
					31
					32
					33
					34
6,324,403	422,032		6,746,435		35
					36
					37

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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	Total Operation and Maintenance			
49	Production-Manufactured Gas (Enter Total of lines 28 and 40)			
50	Production-Natural Gas (Including Expl. and Dev.) (Total lines 29,			
51	Other Gas Supply (Enter Total of lines 30 and 42)			
52	Storage, LNG Terminating and Processing (Total of lines 31 thru			
53	Transmission (Lines 32 and 44)			
54	Distribution (Lines 33 and 45)			
55	Customer Accounts (Line 34)			
56	Customer Service and Informational (Line 35)			
57	Sales (Line 36)			
58	Administrative and General (Lines 37 and 46)			
59	TOTAL Operation and Maint. (Total of lines 49 thru 58)			
60	Other Utility Departments			
61	Operation and Maintenance			
62	TOTAL All Utility Dept. (Total of lines 25, 59, and 61)	91,997,326		91,997,326
63	Utility Plant			
64	Construction (By Utility Departments)			
65	Electric Plant	36,506,612	3,447,556	39,954,168
66	Gas Plant			
67	Other (provide details in footnote):			
68	TOTAL Construction (Total of lines 65 thru 67)	36,506,612	3,447,556	39,954,168
69	Plant Removal (By Utility Departments)			
70	Electric Plant			
71	Gas Plant			
72	Other (provide details in footnote):			
73	TOTAL Plant Removal (Total of lines 70 thru 72)			
74	Other Accounts (Specify, provide details in footnote):			
75	Paid Absences	14,000,952		14,000,952
76	Other Work in Progress	1,261,059		1,261,059
77	Other	4,172,848		4,172,848
78	Other clearing Accounts	20,258		20,258
79				
80				
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	19,455,117		19,455,117
96	TOTAL SALARIES AND WAGES	147,959,055	3,447,556	151,406,611

Name of Respondent Idaho Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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 (f)	Short-Term Firm Point-to-point Reservation (f)	Other Service (f)
1	January	2,625	5	8	2,052	169	376	3	25	
2	February	2,689	17	8	2,072	175	376	3	63	
3	March	2,395	1	8	1,805	147	376		67	
4	Total for Quarter 1	7,709			5,929	491	1,128	6	155	
5	April	2,468	15	8	2,160	141	25		142	
6	May	2,514	28	18	2,306	179	25		4	
7	June	3,339	21	16	2,979	265	25		70	
8	Total for Quarter 2	8,321			7,445	585	75		216	
9	July	3,722	22	16	2,960	286	476			
10	August	3,549	9	17	2,812	261	476			
11	September	3,125	8	18	2,392	232	401		100	
12	Total for Quarter 3	10,396			8,164	779	1,353		100	
13	October	2,342	5	8	1,744	157	401		40	
14	November	2,639	28	8	2,059	179	401			
15	December	2,930	15	8	2,332	197	401			
16	Total for Quarter 4	7,911			6,135	533	1,203		40	
17	Total for Year to Date/Year	34,337			27,673	2,388	3,759	6	511	

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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)	13,288,812
3	Steam	7,248,393	23	Requirements Sales for Resale (See instruction 4, page 311.)	107,606
4	Nuclear		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	2,666,246
5	Hydro-Conventional	6,198,524	25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage		26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
7	Other	66,777	27	Total Energy Losses	1,155,803
8	Less Energy for Pumping		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	17,218,467
9	Net Generation (Enter Total of lines 3 through 8)	13,513,694			
10	Purchases	3,918,389			
11	Power Exchanges:				
12	Received	110,013			
13	Delivered	327,466			
14	Net Exchanges (Line 12 minus line 13)	-217,453			
15	Transmission For Other (Wheeling)				
16	Received	4,775,767			
17	Delivered	4,771,930			
18	Net Transmission for Other (Line 16 minus line 17)	3,837			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	17,218,467			

Name of Respondent Idaho Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of <u>2005/Q4</u>
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MONTHLY PEAKS AND OUTPUT

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

NAME OF SYSTEM: IDAHO POWER COMPANY - SYSTEM LOAD

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirements Sales for Resale & Associated Losses (c)	MONTHLY PEAK		
				Megawatts (See Instr. 4) (d)	Day of Month (e)	Hour (f)
29	January	1,461,872	226,364	2,063	5	7PM
30	February	1,211,886	154,706	2,072	17	8AM
31	March	1,289,493	234,721	1,812	1	8AM
32	April	1,108,096	107,649	1,796	14	8AM
33	May	1,541,433	523,541	1,863	28	6PM
34	June	1,655,077	382,243	2,622	21	4PM
35	July	1,874,482	232,642	2,961	22	4PM
36	August	1,679,139	140,582	2,815	9	5PM
37	September	1,378,417	188,000	2,394	8	6PM
38	October	1,229,496	177,730	1,746	5	8AM
39	November	1,247,378	109,444	2,063	28	8AM
40	December	1,541,698	188,624	2,345	15	8AM
41	TOTAL	17,218,467	2,666,246			

Name of Respondent Idaho Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report 2005/Q4
FOOTNOTE DATA			

Schedule Page: 401 Line No.: 26 Column: b
Included in energy losses

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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 term basis report the Btu content of 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: <i>Jim Bridger</i> (b)	Plant Name: <i>Boardman</i> (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)	779.50	56.05
6	Net Peak Demand on Plant - MW (60 minutes)	698	60
7	Plant Hours Connected to Load	8760	6233
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	4937603000	357180000
13	Cost of Plant: Land and Land Rights	494358	106610
14	Structures and Improvements	63103766	13616489
15	Equipment Costs	383227840	54897896
16	Asset Retirement Costs	0	0
17	Total Cost	446825964	68620995
18	Cost per KW of Installed Capacity (line 17/5) Including	579.9169	1224.2818
19	Production Expenses: Oper, Supv, & Engr	112008	753718
20	Fuel	61522539	4612849
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	4118142	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	5283967	217308
27	Rents	133759	149158
28	Allowances	0	0
29	Maintenance Supervision and Engineering	96600	1952145
30	Maintenance of Structures	0	0
31	Maintenance of Boiler (or reactor) Plant	10733492	0
32	Maintenance of Electric Plant	4146747	0
33	Maintenance of Misc Steam (or Nuclear) Plant	1063755	15071
34	Total Production Expenses	87211009	7700249
35	Expenses per Net KWh	0.0177	0.0216
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels
38	Quantity (Units) of Fuel Burned	2784574	12263
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	9315	14000
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	20.914	83.825
41	Average Cost of Fuel per Unit Burned	21.886	35.716
42	Average Cost of Fuel Burned per Million BTU	1.170	6.074
43	Average Cost of Fuel Burned per KWh Net Gen	0.012	0.000
44	Average BTU per KWh Net Generation	10564.000	0.000

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: <i>Valmy</i> (d)	Plant Name: <i>Danskin</i> (e)	Plant Name: <i>Bennett Mountain</i> (f)	Line No.						
Steam	Gas Turbine	Gas Turbine	1						
Outdoor	Conventional	Conventional	2						
1981	2001	2005	3						
1985	2001	2005	4						
283.50	90.00	172.80	5						
286	83	167	6						
8760	295	372	7						
0	100000	171900	8						
0	0	0	9						
0	0	0	10						
0	6	4	11						
1953610000	10550000	56222000	12						
769351	402745	0	13						
53672955	4314768	1012073	14						
252006875	46919633	52042639	15						
0	0	0	16						
306449181	51637146	53054712	17						
1080.9495	573.7461	307.0296	18						
411920	133678	34625	19						
32846655	1436293	2744349	20						
0	0	0	21						
2777372	0	0	22						
0	0	0	23						
0	0	0	24						
1610776	133523	94828	25						
1293837	94071	119768	26						
42258	0	0	27						
0	0	0	28						
81469	110596	118078	29						
421603	13676	6460	30						
5121874	218967	126113	31						
1465255	0	0	32						
162041	0	0	33						
46235060	2140804	3244221	34						
0.0237	0.2029	0.0577	35						
Coal	Oil	Gas	Gas	36					
Tons	Barrels	MCF	MCF	37					
947851	0	5703	156347	0	0	467919	0	0	38
9988	0	138778	1038	0	0	1038	0	0	39
33.003	0.000	88.298	9.187	0.000	0.000	5.865	0.000	0.000	40
34.118	0.000	81.262	9.187	0.000	0.000	5.865	0.000	0.000	41
1.725	0.000	13.941	8.850	0.000	0.000	5.650	0.000	0.000	42
0.017	0.000	0.000	0.136	0.000	0.000	0.049	0.000	0.000	43
9611.000	0.000	0.000	15383.000	0.000	0.000	8639.000	0.000	0.000	44

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Name of Respondent Idaho Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report 2005/Q4
FOOTNOTE DATA			

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 Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of <u>2005/Q4</u>
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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)	96	52
7	Plant Hours Connect to Load	7,988	8,585
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	112	80
10	(b) Under the Most Adverse Oper Conditions	0	74
11	Average Number of Employees	4	4
12	Net Generation, Exclusive of Plant Use - Kwh	224,948,000	287,702,000
13	Cost of Plant		
14	Land and Land Rights	875,318	463,556
15	Structures and Improvements	11,797,544	666,849
16	Reservoirs, Dams, and Waterways	4,242,904	7,428,401
17	Equipment Costs	31,069,025	6,536,751
18	Roads, Railroads, and Bridges	306,333	486,477
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	48,291,124	15,582,034
21	Cost per KW of Installed Capacity (line 20 / 5)	523.1974	207.7605
22	Production Expenses		
23	Operation Supervision and Engineering	198,972	468,653
24	Water for Power	1,037,569	255,122
25	Hydraulic Expenses	232,283	425,918
26	Electric Expenses	35,513	19,213
27	Misc Hydraulic Power Generation Expenses	178,011	84,352
28	Rents	141	2,858
29	Maintenance Supervision and Engineering	169,493	53,040
30	Maintenance of Structures	63,734	38,503
31	Maintenance of Reservoirs, Dams, and Waterways	1,866	4,106
32	Maintenance of Electric Plant	294,999	157,058
33	Maintenance of Misc Hydraulic Plant	55,012	175,983
34	Total Production Expenses (total 23 thru 33)	2,267,593	1,684,806
35	Expenses per net KWh	0.0101	0.0059

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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	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)	445	26
7	Plant Hours Connect to Load	8,688	8,695
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	450	24
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	1,589,522,000	158,637,000
13	Cost of Plant		
14	Land and Land Rights	1,558,955	205,375
15	Structures and Improvements	2,414,069	2,564,034
16	Reservoirs, Dams, and Waterways	52,619,458	3,371,066
17	Equipment Costs	15,059,339	3,080,461
18	Roads, Railroads, and Bridges	819,192	304,683
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	72,471,013	9,525,619
21	Cost per KW of Installed Capacity (line 20 / 5)	185.1111	437.5571
22	Production Expenses		
23	Operation Supervision and Engineering	241,985	118,566
24	Water for Power	82,158	490,071
25	Hydraulic Expenses	195,773	161,898
26	Electric Expenses	129,110	57,397
27	Misc Hydraulic Power Generation Expenses	154,149	50,458
28	Rents	61,568	0
29	Maintenance Supervision and Engineering	186,501	45,844
30	Maintenance of Structures	29,887	6,762
31	Maintenance of Reservoirs, Dams, and Waterways	111,775	77,846
32	Maintenance of Electric Plant	292,817	23,883
33	Maintenance of Misc Hydraulic Plant	620,591	111,565
34	Total Production Expenses (total 23 thru 33)	2,106,314	1,144,290
35	Expenses per net KWh	0.0013	0.0072

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of <u>2005/Q4</u>
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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)	34	13
7	Plant Hours Connect to Load	8,753	8,760
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	39	13
10	(b) Under the Most Adverse Oper Conditions	32	11
11	Average Number of Employees	3	1
12	Net Generation, Exclusive of Plant Use - Kwh	190,867,000	82,726,000
13	Cost of Plant		
14	Land and Land Rights	172,970	311,407
15	Structures and Improvements	1,499,664	1,138,033
16	Reservoirs, Dams, and Waterways	4,314,125	512,401
17	Equipment Costs	4,758,636	1,985,438
18	Roads, Railroads, and Bridges	29,359	51,383
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	10,774,754	3,998,662
21	Cost per KW of Installed Capacity (line 20 / 5)	312.3117	319.8930
22	Production Expenses		
23	Operation Supervision and Engineering	330,231	124,505
24	Water for Power	76,447	49,254
25	Hydraulic Expenses	303,476	187,448
26	Electric Expenses	16,637	13,879
27	Misc Hydraulic Power Generation Expenses	113,586	51,443
28	Rents	0	25
29	Maintenance Supervision and Engineering	99,661	32,296
30	Maintenance of Structures	66,898	36,045
31	Maintenance of Reservoirs, Dams, and Waterways	213,718	1,378
32	Maintenance of Electric Plant	103,879	60,417
33	Maintenance of Misc Hydraulic Plant	284,723	54,927
34	Total Production Expenses (total 23 thru 33)	1,609,256	611,617
35	Expenses per net KWh	0.0084	0.0074

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Name of Respondent Idaho Power Company	This Report is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report 2005/Q4
FOOTNOTE DATA			

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

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

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

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

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

Upstream storage in Brownlee Reservoir.

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

Upstream storage in Brownlee Reservoir

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

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

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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	13,238	1,730,795
3	Thousand Springs	1912	8.80	6.3	52,050	4,691,209
4						
5						
6	Internal Combustion:					
7	Salmon Diesel (1)	1967	5.00	2.0	5	901,055
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9						
10						
11	(1) Salmon units are classified as standby.					
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Name of Respondent Idaho Power Company	This Report is:		Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
	(1) <input checked="" type="checkbox"/> An Original	(2) <input type="checkbox"/> A Resubmission		

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		Kind of Fuel (k)	Fuel Costs (in cents per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
						1
692,318	97,668		129,876			2
533,092	76,130		85,426			3
						4
						5
						6
180,211				Diesel		7
						8
						9
						10
						11
						12
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TRANSMISSION LINE STATISTICS

- 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.
- 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.
- Report data by individual lines for all voltages if so required by a State commission.
- Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
- 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.
- Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	Boardman	Slatt	500.00	500.00	S Tower	1.79		1
2								
3	Borah	Midpoint	345.00	500.00	S Tower	85.16		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	79.37		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	46.18		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	74.87		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	18.60		1
22	Boise Bench	Caldwell	230.00	230.00	S Tower	4.40		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	10.80		2
27	Caldwell	Ontario	230.00	230.00	H Wood	27.34		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	Boise Bench	Midpoint #1	230.00	230.00	S Tower	0.86		1
31	Boise Bench	Midpoint #1	230.00	230.00	H Wood	108.11		1
32	Brownlee	Quartz Jct	230.00	230.00	S Tower	1.52		1
33	Brownlee	Quartz Jct	230.00	230.00	H Wood	41.74		1
34	Brownlee	Boise Bench #1 & #2	230.00	230.00	S Tower	99.98		2
35	Oxbow	Brownlee	230.00	230.00	S Tower	10.25		2
36					TOTAL	4,690.83	11.02	156

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
2X1780 ACSR		446,708	446,708					1
								2
1272 ACSR	256,381	21,776,998	22,033,379					3
1272 ACSR	483,309	15,740,328	16,223,637					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	5,440,990	5,724,133					7
715.5 ACSR	64,851	6,047,015	6,111,866					8
715.5 ACSR	51,448	347,946	399,394					9
								10
795 ACSR	51,414	2,317,071	2,368,485					11
715.5 ACSR	9,145	1,001,738	1,010,883					12
1272 ACSR	108,301	2,328,646	2,436,947					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	20,246,910	21,923,748					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	817,054	2,761,586	3,578,640					22
715.5 ACSR								23
1272 ACSR	2,999,026	6,532,790	9,531,816					24
795 AAC		80,895	80,895					25
954 ACSR		16,463,767	16,463,767					26
2X954 ACSR	194,763	5,902,042	6,096,805					27
1272 ACSR								28
1272 ACSR	81,701	1,666,354	1,748,055					29
715.5 ACSR	336,186	3,689,418	4,025,604					30
715.5 ACSR								31
795 ACSR	42,995	1,782,886	1,825,881					32
795 ACSR								33
VARIOUS	261,229	7,997,000	8,258,229					34
1272 ACSR	6,033	1,191,291	1,197,324					35
	25,916,298	286,562,651	312,478,949	5,798,097	2,620,886	1,565,610	9,984,593	36

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	Boise Bench	Midpoint #2	230.00	230.00	S Tower	3.42		1
2	Boise Bench	Midpoint #2	230.00	230.00	H Wood	102.52		1
3	Oxbow	Palette Jct	230.00	230.00	S Tower	20.20		2
4	Palette Jct	Imnaha	230.00	230.00	H Wood	23.85		2
5	Hells Canyon	Palette Jct	230.00	230.00	S Tower	8.24		2
6	Brownlee	Boise Bench	230.00	230.00	S Tower	102.30		2
7	Boise Bench	Midpoint #3	230.00	230.00	H Wood	106.35		1
8	Palette Jct	Enterprise	230.00	230.00	H Wood	28.37		1
9	Borah	Brady #2	230.00	230.00	S Tower	0.43		1
10	Borah	Brady #2	230.00	230.00	H Wood	3.58		1
11	Borah	Brady #1	230.00	230.00	H Wood	3.97		1
12								
13	Goshen	State Line	161.00	161.00	H Wood	90.49		1
14	Don	Goshen	161.00	161.00	S Tower	2.37		2
15	Don	Goshen	161.00	161.00	H Wood	46.19		2
16								
17	American Falls Power Plant	Adelaide	138.00	138.00	H Wood	80.64		2
18	American Falls Power Plant	Adelaide	138.00	138.00	S P Wood	2.58		2
19	Minidoka Loop	Adelaide	138.00	138.00	S Tower	1.11		2
20	Nampa	Caldwell	138.00	138.00	S P Wood	10.73		2
21	Upper Salmon	Mountain Home Jct		138.00	H Wood	4.31		1
22	Upper Salmon	Mountain Home Jct	138.00	138.00	H Wood	49.32		1
23	Upper Salmon	Cliff	138.00	138.00	H Wood	30.80		1
24	Eastgate	Russet	138.00	138.00	S P Wood	2.07		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	84.90		2
29	Emmett Jct	Payette	138.00	138.00	H Wood	62.80		2
30	Mountain Home AFB Tap		138.00	138.00	H Wood	6.21		1
31	Ontario	Quartz	138.00	138.00	H Wood	73.42		1
32	King	American Falls PP	138.00	138.00	S Tower	1.02		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	4,690.83	11.02	156

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
715.5 ACSR	227,825	5,413,410	5,641,235					1
VARIOUS								2
1272 ACSR	23,308	2,032,869	2,056,177					3
1272 ACSR	138,477	1,220,528	1,359,005					4
1272 ACSR	10,737	1,252,130	1,262,867					5
954 ACSR	170,694	5,555,559	5,726,253					6
715.5 ACSR	247,857	4,899,440	5,147,297					7
1272 ACSR	51,122	1,633,094	1,684,216					8
1272 ACSR	3,068	200,632	203,700					9
715.5 ACSR								10
1272 ACSR	10,064	180,008	190,072					11
								12
250 COPPER	16,155	648,382	664,537					13
715.5 ACSR	76,041	1,622,852	1,698,893					14
397.5 ACSR								15
								16
250 COPPER	26,507	2,346,862	2,373,369					17
250 COPPER								18
715.5 ACSR	15,088	249,232	264,320					19
795 AAC	157,432	1,533,646	1,691,078					20
795 ACSR	47,687	1,696,746	1,744,433					21
VARIOUS								22
795 ACSR	43,568	764,183	807,751					23
795 AAC	270,823	557,504	828,327					24
VARIOUS	564,932	3,443,959	4,008,891					25
VARIOUS								26
VARIOUS								27
VARIOUS	76,823	1,377,411	1,454,234					28
VARIOUS	30,918	1,316,460	1,347,378					29
397.5 ACSR	1,955		1,955					30
VARIOUS	34,428	1,486,208	1,520,636					31
715.5 ACSR	148,914	4,282,784	4,431,698					32
715.5 ACSR								33
715.5 ACSR								34
410	4,191	309,827	314,018					35
	25,916,298	286,562,651	312,478,949	5,798,097	2,620,886	1,565,610	9,984,593	36

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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TRANSMISSION LINE STATISTICS

- 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.
- 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.
- Report data by individual lines for all voltages if so required by a State commission.
- Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
- 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.
- Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
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	73.56		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	67.21		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	38.49		1
15	Oxbow	McCall	138.00	138.00	S P Wood	1.65		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	13.48		1
19	American Falls	Kramer Sub	138.00	138.00	S P Wood	18.40		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	25.21		2
22	Twin Falls	Russett	138.00	138.00	S P Wood	1.73		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	3.98	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	69.00	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 Tap		138.00	138.00	S P Steel	0.10		1
36					TOTAL	4,690.83	11.02	156

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
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	2,357,968	2,531,651					4
VARIOUS	225,602	1,629,593	1,855,195					5
397.5 ACSR	92,173	2,362,416	2,454,589					6
VARIOUS	20	77,199	77,219					7
715.5 ACSR	1,727,471	5,250,571	6,978,042					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	84,183	1,752,478	1,836,661					14
397.5 ACSR								15
715.5 ACSR	211,131	1,421,002	1,632,133					16
715.5 ACSR	3,324	1,077,727	1,081,051					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	1,054,909	1,100,898					25
715.5 ACSR	14,697	632,718	647,415					26
795 AAC		49,642	49,642					27
795 AAC	489,037	1,963,865	2,452,902					28
1272 ACSR	935,725	2,825,718	3,761,443					29
1272 ACSR	34,687	827,093	861,780					30
715.5 ACSR		2,942,956	2,942,956					31
795 AAC		423,821	423,821					32
1272 ACSR	140,412	709,148	849,560					33
795 ACSR	473,875	1,068,446	1,542,321					34
954 ACSR		58,005	58,005					35
	25,916,298	286,562,651	312,478,949	5,798,097	2,620,886	1,565,610	9,984,593	36

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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TRANSMISSION LINE STATISTICS

- 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.
- 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.
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- Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
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- Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits (h)
	From (a)	To (b)	Operating (c)	Designed (d)		On Structure of Line Designated (f)	On Structures of Another Line (g)	
1	Valivue Tap		138.00	138.00	S P Steel	0.82		2
2	Kinport	Don #1	138.00	138.00	S Tower	1.24		2
3	Twin Falls PP Tap		138.00	138.00	H Wood	0.82		1
4	American Falls PP	Americian Falls Trans ST	138.00	138.00	S P Steel	0.38		1
5	Lower Salmon	King Tie	138.00	138.00	H Wood	0.22		1
6	C J Strike	Strike Jct	138.00	138.00	S Tower	4.30		2
7	Strike Jct	Mountain Home Jct	138.00	138.00	H Wood	26.55		1
8								
9	Strike Jct	Bowmont		138.00	H Wood	0.05		1
10	Strike Jct	Bowmont	138.00	138.00	S Tower	0.36		1
11	Strike Jct	Bowmont	138.00	138.00	H Wood	68.14		1
12	Lucky Peak	Lucky Peak Jct	138.00	138.00	H Wood	4.43		2
13	Bliss	King	138.00	138.00	H Wood	10.44		1
14	Milner Deadend	Milner PP	138.00	138.00	S P Wood	1.31		1
15	Swan Falls Tap		138.00	138.00	H Wood	0.95		1
16								
17								
18								
19	Hines	BPA (Harney)	115.00	115.00	H Wood	3.28		1
20								
21								
22	69 Kv Lines		69.00	69.00	H Wood	166.31		1
23	69 Kv Lines		69.00	69.00	S P Wood	1,003.77		1
24								
25								
26	46 Kv Lines		46.00	46.00	S P Wood	428.86		1
27								
28	Government Agency ROWs							
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	4,690.83	11.02	156

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
795 ACSR		351,497	351,497					1
715.5 ACSR	1,174	212,777	213,951					2
250 COPPER	58	53,888	53,946					3
715.5 ACSR		76,560	76,560					4
397.5 ACSR		4,406	4,406					5
715.5 ACSR	1,074	253,872	254,946					6
397.5 ACSR	4,355	525,528	529,883					7
								8
715.5 ACSR	29,902	1,501,004	1,530,906					9
715.5 ACSR								10
								11
715.5 ACSR	7	279,481	279,488					12
715.5 ACSR	5,620	954,169	959,789					13
715.5 ACSR	2,814	183,606	186,420					14
397.5 ACSR	12,885	261,511	274,396					15
								16
								17
								18
397.5 ACSR	1,978	63,404	65,382					19
								20
								21
VARIOUS	928,990	31,025,493	31,954,483					22
VARIOUS								23
								24
								25
VARIOUS	176,265	7,648,221	7,824,486					26
								27
	5,718,852		5,718,852					28
				5,798,097	2,620,886	1,565,610	9,984,593	29
								30
								31
								32
								33
								34
								35
	25,916,298	286,562,651	312,478,949	5,798,097	2,620,886	1,565,610	9,984,593	36

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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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 completed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION		Line Length in Miles (c)	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)		Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	Eagle	Star	1.35	SP Wood	15.00	1	1
2	Karcher	Zilog Tap	2.09	SP Steel	18.00	1	1
3	Bennett Mtn	Rattlesnake	4.48	SP Steel	12.00	1	1
4							
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6							
7							
8							
9							
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43							
44	TOTAL		7.92		45.00	3	3

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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TRANSMISSION LINES ADDED DURING YEAR (Continued)

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

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

CONDUCTORS			Voltage KV (Operating) (k)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)		Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
795	AAC	Vert 6'	138		1,846,815	1,096,141		2,942,956	1
795	AAC	Vert 6'	69		259,183	164,638		423,821	2
1272	ACSR	Vert 9'	230	81,701	894,543	771,811		1,748,055	3
									4
									5
									6
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				81,701	3,000,541	2,032,590		5,114,832	44

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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	138.00	38.00	13.80
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 Cascade Emmett CSPP	distribution	69.00	13.00	
21	Boise	distribution	138.00	13.00	
22	Borah	transmission	345.00	230.00	13.80
23	Bowmont	distribution	69.00	46.00	6.90
24	Bowmont	distribution	138.00	34.50	
25	Bowmont	distribution	138.00	69.00	13.80
26	Brady	transmission	46.00	12.50	
27	Brady	transmission	230.00	138.00	13.80
28	Brownlee - attended	transmission	230.00	13.80	
29	Bruneau Bridge	distribution	138.00	34.50	
30	Buckhorn	distribution	69.00	35.00	
31	Bucyrus	distribution	46.00	7.20	
32	Buhl	distribution	46.00	13.00	
33	Burley Rural	distribution	69.00	13.00	
34	Butler	distribution	138.00	13.00	
35	Caldwell	distribution	138.00	13.00	
36	Caldwell	distribution	138.00	69.00	13.00
37	Caldwell	transmission	230.00	138.00	12.50
38	Canyon Creek	distribution	138.00	34.50	
39	Canyon Creek	distribution	138.00	69.00	12.50
40	Cascade Power Plant - attended	transmission	69.00	4.60	

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
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	3	1				14
69	3					15
15	1					16
42	2					17
75	3					18
374	3					19
12	1					20
67	3					21
450	3	1				22
8	3					23
18	1					24
25	1					25
		6				26
300	3					27
734	5	1				28
30	2					29
20	1					30
6	1	3				31
20	2					32
12	1					33
48	2					34
39	2	1				35
50	2					36
240	2					37
15	1					38
		1				39
12	1					40

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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	Cloverdale	transmission	138.00	69.00	12.50
6	Dale	distribution	69.00	13.00	
7	Dale	distribution	138.00	34.50	
8	Dale	distribution	138.00	46.00	12.50
9	Danskin	transmission	138.00	12.00	
10	Don	distribution	138.00	7.60	
11	Don	distribution	138.00	13.20	
12	Don	distribution	138.00	13.80	
13	DRAM	distribution	138.00	13.00	
14	DRAM	distribution	230.00	138.00	13.80
15	Duffin	distribution	138.00	34.50	
16	Eagle	distribution	138.00	13.00	
17	Eastgate	distribution	138.00	13.00	
18	Eckert	distribution	138.00	36.20	
19	Eden	distribution	138.00	34.50	
20	Eden	distribution	138.00	46.00	12.50
21	Elkhorn	distribution	138.00	12.00	
22	Elmore	transmission	138.00	34.50	
23	Elmore	distribution	138.00	69.00	12.50
24	Emmett	distribution	138.00	12.50	
25	Emmett	distribution	138.00	69.00	12.50
26	Falls	distribution	46.00	12.50	
27	Filer	distribution	46.00	12.50	
28	Flying H	distribution	69.00	2.40	
29	Fort Hall	distribution	46.00	12.50	
30	Fossil Gulch	distribution	138.00	13.80	4.60
31	Fossil Gulch	distribution	138.00	34.50	
32	Fremont	transmission	138.00	46.00	12.50
33	Gary	distribution	138.00	13.00	
34	Gem	distribution	69.00	13.00	
35	Golden Valley	distribution	69.00	12.50	
36	Gowen Substation	distribution	138.00	35.00	
37	Grindstone	distribution	35.00	12.50	
38	Grove	distribution	138.00	12.50	
39	Hagerman	distribution	46.00	12.50	
40	Hailey	distribution	138.00	12.50	

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
48	2					1
4	1					2
33	4					3
48	2					4
50	2					5
		1				6
24	1					7
25	1					8
96	2					9
		1				10
92	6	9				11
26	1	1				12
134	8					13
160	2					14
36	2					15
35	2					16
36	2					17
18	1					18
24	1					19
15	1					20
15	2					21
16	1					22
30	2					23
15	1					24
25	1					25
17	2					26
10	1					27
15	2					28
10	1					29
8	1					30
15	1					31
50	3	1				32
36	2					33
17	2					34
10	1	1				35
24	1					36
10	2					37
72	3					38
12	2					39
20	1					40

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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SUBSTATIONS

- Report below the information called for concerning substations of the respondent as of the end of the year.
- Substations which serve only one industrial or street railway customer should not be listed below.
- 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.
- 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	Houston	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	Karcher	distribution	138.00	13.09	
20	Kenyon	distribution	69.00	12.50	
21	Ketchum	distribution	138.00	12.50	
22	Kinport	transmission	161.00	46.00	13.00
23	Kinport	transmission	230.00	138.00	12.50
24	Kinport	transmission	230.00	138.00	13.80
25	Kinport	transmission	345.00	230.00	13.80
26	Kramer	distribution	138.00	34.50	
27	Kramer	distribution	138.00	13.00	
28	Kuna	distribution	138.00	13.00	
29	Lake Fork	distribution	138.00	36.20	
30	Lake Fork	transmission	138.00	69.00	12.50
31	Lamb	distribution	138.00	13.09	
32	Lansing	distribution	69.00	13.00	
33	Lincoln	distribution	138.00	13.00	
34	Linden	distribution	138.00	13.00	
35	Locust	distribution	138.00	34.50	
36	Locust	transmission	230.00	138.00	13.00
37	Lower Malad - attended	transmission	138.00	7.20	
38	Lower Salmon - attended	transmission	138.00	13.80	
39	Map Rock	distribution	69.00	12.50	
40	McCall	distribution	69.00	12.50	

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of <u>2005/Q4</u>
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SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
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
10	1	1				12
300	3					13
24	1					14
12	1					15
20	1					16
30	2					17
15	1					18
12	1					19
20	2					20
42	2					21
		7				22
180	1					23
180	1					24
600	3	1				25
12	1					26
18	1					27
15	1					28
18	1					29
15	1					30
18	1					31
12	1					32
11	1					33
33	2					34
48	2					35
360	2					36
15	1					37
70	4					38
10	1					39
8	1					40

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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	138.00	35.00	
2	McCall	distribution	138.00	69.00	12.50
3	Meridian	distribution	138.00	13.00	
4	Micron	distribution	138.00	12.50	
5	Midpoint	transmission	230.00	138.00	12.50
6	Midpoint	transmission	345.00	230.00	13.80
7	Midpoint	transmission	500.00	345.00	
8	Midrose	distribution	138.00	13.09	
9	Milner	distribution	69.00	38.00	13.80
10	Milner	distribution	69.00	38.00	7.20
11	Milner	distribution	138.00	34.50	
12	Milner PP - attended	transmission	138.00	13.80	
13	Moonstone	distribution	138.00	34.50	
14	Mora	distribution	138.00	34.50	
15	Moreland	distribution	46.00	12.50	
16	Moreland	distribution	46.00	34.50	12.50
17	Mountain Home	distribution	69.00	12.50	
18	Mountain Home Air Force Base	distribution	69.00	12.50	
19	Mountain Home Air Force Base	distribution	138.00	12.50	
20	Nampa	distribution	230.00	138.00	
21	Nampa	distribution	138.00	12.50	
22	Nampa	distribution	138.00	69.00	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	13.80	4.60
39	Sailor Creek	distribution	138.00	34.50	
40	Salmon	distribution	69.00	12.50	

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
18	1					1
30	1					2
36	2					3
48	4					4
120	1					5
720	2					6
1000	4					7
18	1					8
75	3	1				9
8	3	1				10
16	1					11
36	1					12
12	1					13
33	2					14
8	1					15
10	3	1				16
12	1					17
		1				18
18	1					19
180	1					20
50	3					21
25	1					22
10	4					23
10	1					24
11	1					25
10	1					26
12	1					27
36	2					28
22	3					29
50	3					30
22	2					31
42	2					32
36	2					33
18	1					34
5	3	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:		Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
	(1) <input checked="" type="checkbox"/> An Original	(2) <input type="checkbox"/> A Resubmission		

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	State	distribution	69.00	12.50	
13	Stoddard	distribution	138.00	13.00	
14	Strike Power Plant - attended	transmission	138.00	13.80	
15	Sugar	distribution	138.00	34.50	
16	Swan Falls - attended	transmission	138.00	6.90	
17	Taber	distribution	46.00	12.50	
18	Ten Mile	distribution	138.00	13.09	
19	Terry	distribution	138.00	12.50	
20	Thousand Springs - attended	transmission	46.00	6.90	
21	Thousand Springs - attended	transmission	7.00	2.40	
22	Toponis	distribution	138.00	34.50	
23	Twin Falls	distribution	138.00	13.00	
24	Twin Falls	distribution	138.00	46.00	12.50
25	Twin Falls PP - attended	transmission	138.00	7.20	
26	Twin Falls PP - attended	transmission	138.00	13.20	
27	Upper Malad - attended	transmission	46.00	7.20	
28	Upper Salmon- attended	transmission	138.00	7.20	
29	Ustick	distribution	138.00	12.50	
30	Vallivue	distribution	138.00	13.09	
31	Victory	distribution	138.00	12.50	
32	Ware	distribution	69.00	12.50	
33	Weiser	distribution	69.00	12.50	
34	Weiser	distribution	138.00	69.00	12.50
35	Wilder	distribution	69.00	13.00	
36	Wye	distribution	138.00	13.00	
37	Zilog	distribution	69.00	12.50	
38					
39					
40	The above are all State of Idaho				

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
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
33	2					12
15	1					13
83	3					14
10	1					15
18	1					16
5	1					17
18	1					18
42	3					19
8	1					20
2	1					21
18	1					22
40	2					23
33	2					24
9	1					25
72	1					26
8	1					27
36	4					28
44	2					29
18	1					30
24	1					31
12	1					32
20	2					33
25	1					34
10	1					35
56	3					36
25	2					37
						38
						39
						40

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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					
2	Montana:				
3	Peterson	transmission	138.00	38.00	12.50
4					
5	Nevada:				
6	Valmy - attended	transmission	345.00	21.30	
7	Wells	transmission	138.00	69.00	12.50
8					
9	Oregon:				
10	Boardman - attended	transmission	500.00	24.00	
11	Cairo	distribution	69.00	12.50	
12	Hells Canyon - attended	transmission	230.00	13.80	
13	Hines	transmission	138.00	115.00	12.50
14	Malheur Butte	distribution	69.00	34.50	12.50
15	Nyssa	distribution	69.00	12.50	
16	Ontario	distribution	138.00	12.50	
17	Ontario	distribution	138.00	69.00	12.50
18	Ontario	distribution	230.00	138.00	12.50
19	Ore-Ida	distribution	69.00	12.50	
20	Oxbow - attended	transmission	69.00	38.00	12.50
21	Oxbow - attended	transmission	230.00	13.80	
22	Oxbow - attended	transmission	230.00	138.00	13.80
23	Quartz	transmission	138.00	69.00	12.50
24	Quartz	transmission	138.00	80.00	12.50
25	Vale	distribution	69.00	13.09	
26					
27	Wyoming:				
28	Jim Bridger - attended	transmission	345.00	22.00	
29					
30					
31					
32					
33					
34					
35	Transformers-distribution substations under 10,000				
36	KVA 83 unattended.				
37					
38					
39					
40					

Name of Respondent Idaho Power Company	This Report Is: (1) <input checked="" type="checkbox"/> An Original (2) <input type="checkbox"/> A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2006	Year/Period of Report End of 2005/Q4
---	---	--	---

SUBSTATIONS (Continued)

5. Show in columns (l), (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			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVA) (k)	
						1
						2
30	3	1				3
						4
						5
150	1					6
26	4					7
						8
						9
55	1					10
12	1					11
500	3	1				12
40	1					13
10	3					14
20	2					15
38	2					16
65	3					17
240	2					18
15	1					19
10	3	1				20
244	2					21
100	1					22
30	2					23
133	4					24
10	1					25
						26
						27
748	1					28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

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ANNUAL REPORT
IDAHO SUPPLEMENT TO FERC FORM 1
MULTI-STATE ELECTRIC COMPANIES

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3	Accumulated Provision for Uncollectible Accounts
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11	Electric Operating Revenues
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STATEMENT OF INCOME FOR THE YEAR

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

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL	
			Current Year (c)	Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400).....	11	\$ 802,914,413	\$ 756,779,337
3	Operating Expenses			
4	Operation Expenses (401).....	15	474,244,701	491,365,712
5	Maintenance Expenses (402).....	15	55,287,956	54,187,809
6	Depreciation Expense (403).....		85,895,690	84,052,059
7	Amort. & Depl. of Utility Plant (404-405).....		6,781,326	9,092,999
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).....		11,370,700	(18,929,738)
13	Taxes Other Than Income Taxes (408.1).....	2	18,828,248	17,219,724
14	Income Taxes - Federal (409.1).....	2	67,059,990	17,839,912
15	- Other (409.1).....	2	9,235,170	7,958,131
16	Provision for Deferred Income Taxes (410.1 & 411.1) Net.....	2	(35,537,390)	(18,569,538)
17	Investment Tax Credit Adj. - Net (411.4).....	2	2,016,462	(1,042,465)
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).....		695,182,852	643,174,605
24				
25	Net Utility Operating Income (Enter Total of line 2 less 23)		\$ 107,731,561	\$ 113,604,732
26	(Carry forward to page 11, line 27).....			

TAXES ALLOCATED TO IDAHO

<u>Kind of Tax</u>	<u>Taxes Charged During Year</u>
Taxes Other Than Income Taxes:	
Labor Related:	
FICA.....	\$ 8,704,694
FUTA.....	103,807
State Unemployment.....	234,985
Payroll Deduction & Loading.....	(9,043,485)
Total Labor Related.....	<u>0</u>
Property Taxes.....	15,817,822
Kilowatt-hour Tax.....	1,160,927
Licenses.....	3,242
Regulatory Commission Fees.....	1,670,843
Irrigation PIC.....	175,414
Total Taxes Other Than Income Taxes.....	<u>18,828,248</u>
Federal Income Taxes.....	67,059,990
State Income Taxes.....	9,235,170
Deferred Income Taxes.....	(35,537,390)
Investment Tax Credit Adjustment - Net.....	2,016,462
Total Taxes Allocated to Idaho.....	<u><u>\$ 61,602,480</u></u>

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).....	\$ 11,863,100	\$ 10,522,187
2	Customer Accounts Receivable (Account 142).....	45,440,589	49,830,007
3	Other Accounts Receivable (Account 143).....	5,201,303	6,860,636
4	(Disclose any capital stock subscription received)		
5	Total.....	62,504,991	67,212,830
6			
7	Less: Accumulated Provision for Uncollectible		
8	Accounts-Cr. (Account 144).....	1,363,426	833,238
9			
10	Total, Less Accumulated Provision for		
11	Uncollectible Accounts.....	\$ 61,141,566	\$ 66,379,592
12			
13			
14	Notes Receivable - Account 141: (at 12-31-05)		
15	Directors, officers, and employees - \$ 5,812,291		
16			
17			
18	Other Accounts Receivable - Account 143: (at 12-31-05)		
19	Directors, officers, and employees - \$ 1,422		
20			

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

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

Line No.	Item (a)	Utility Customers (b)	Mdse, Jobbing & Contract Work (c)	Officers and Employees (d)	Other (e)	Total (f)
21						
22	Bal. beginning of year	\$ 1,309,913	\$	\$	\$ (546,498)	\$ 763,415
23	Prov. for uncollectibles					
24	for year.....	53,513			16,310	69,823
25	Accounts written off.....					
26	Coll. of accounts					
27	written off.....					
28	Adjustments (explain).....					
29						
30						
31						
32	Balance end of year.....	\$ 1,363,426	\$ -	\$ -	\$ (530,188)	\$ 833,238
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		Balance End of Year (e)	Interest For Year (f)
			Debits (c)	Credits (d)		
1	<u>Account 145:</u>					
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12	<u>Account 146:</u>					
13						
14	Rocky Mountain Communication	\$ 92,025	\$ 310,428	\$ 302,775	\$ 99,678	
15						
16	IDACORP, Inc.....	\$ 1,205,519	\$ 66,708,406	\$ 67,376,519	\$ 537,406	
17						
18	IDACORP Energy Solutions.....	\$ 407	\$ -	\$ 407	\$ 0	
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31	Total Account 146.....	\$ 1,297,952	\$ 67,018,833	\$ 67,679,701	\$ 637,084	
32						

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STATE OF IDAHO - TOTAL SYSTEM DATA					
GAIN OR LOSS ON DISPOSITION OF PROPERTY (Account 421.1 and 421.2)					
<p>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.</p> <p>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).</p> <p>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.)</p>					
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	American Falls House Sale - operating	\$ 15,158		\$ (14,637)	
5	Buyer: Cesareo Rodriguez August 2005				
6					
7	JUMP Substation (reclassify Acctg Entry)	63,565		(13,026)	
8	November 2005				
9					
10					
11					
12	Miscellaneous items (2)			(1,764)	
13					
14	Total gain.....	\$ 78,723		\$ (29,427)	
15					
16	Loss on disposition of				
17	property:				
18	Retire PC's & Software previously	\$ 106,328			\$ 106,328
19	held by IdaCorp energy December 2005				
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31	Total loss.....	\$ 106,328			\$ 106,328

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	95,900
2	AERO-GRAPHICS	Mapping Services	12,957
3	ASCENTIUM CORPORATION	PM Consultant	130,669
4	ASHLEY LAND SERVICES	Environmental Services	112,971
5	ATER, WYNNE LLP	Legal Services	130,397
6	AURORA CONSULTING GROUP	Management Services	19,927
7	AUTODESK INC	Management Services	10,925
8	BCON WSA INTERNATIONAL, INC	Management Services	18,625
9	BIDART & ROSS INC	Management Services	72,207
10	BLACKBURN & JONES LLP	Legal Services	235,645
11	BLUE WORLD INFORMATION TECHNOL	Management Services	32,296
12	BOISE BUSINESS CONSULTING, INC	Management Services	80,188
13	BOISE STATE UNIVERSITY	Management Services	34,594
14	BRENNEMAN, JOHN	Lobby Service	73,302
15	BROWN RUDNICK BERLACK ISRAELS	Lobby Service	54,000
16	BROWNSTEIN HYATT & FARBER, P C	Legal Services	664,157
17	BUSINESS LEGAL CONSULTING	Legal Services	14,641
18	CAMINUS CORPORATION	Customer Service Support	29,316
19	CAPROCK GROUP INC, THE	Management Services	16,000
20	CASCADE ENERGY ENGINEERING INC	Engineering Services	41,030
21	CH2M HILL	Engineering Services	31,102
22	CHAVEZ WRITING & EDITING, INC	Management Services	49,235
23	CHURCH, JOHN S	Economic Services	66,000
24	CONNOLLY & SMYSER, CHTD	Management Services	49,178
25	CONNOR CLAIMS SPECIALISTS	Management Services	23,037
26	CORNERSTONE SYSTEMS INC	Computer Support Services	586,518
27	CRI ADVANTAGE	Computer Support Services	93,433
28	CTA ARCHITECTS	Architect Service	33,117
29	DAVID EVANS AND ASSOCIATES	Management Services	97,934
30	DAVIS WRIGHT TREMAINE LLP	Legal Services	997,720
31	DELOITTE & TOUCHE	Accounting Services	906,466
32	DELOITTE TAX LLP	Accounting Services	28,165
33	DESERT RESEARCH INSTITUTE	Environmental Services	267,833
34	DEVELOPMENT DIMENSIONS	Computer Support Services	33,320
35	DEVINE, TARBELL & ASSOC INC	Environmental Services	25,519
36	DHI INC	Environmental Services	37,120
37	EAGLE CAP CONSULTING INC	Environmental Services	184,055
38	ECOANALYSTS INC	Environmental Services	36,465
39	ELECTRONIC DATA SOLUTIONS	Computer Support Services	14,135
40	ENGINEERING & HYDROSYSTEMS, IN	Engineering Services	34,092
41	EOP GROUP	Consulting Services	80,000
42	ERNST & YOUNG LLP	Accounting Services	197,183
43	FOUND LAKE CONSULTING INC	Environmental Services	22,229
44	GARRAD HASSAN AMERICA INC	Environmental Services	41,809
45	GLOBAL INSIGHT	Management Services	23,956

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	GOLDER ASSOCIATES	Environmental Services	87,721
47	GRID WEST	Management Services	220,648
48	HALL FARLEY OBERRECHT & B	Legal Services	39,523
49	HDR ENGINEERING, INC	Engineering Services	547,081
50	HR MANAGEMENT SOLUTIONS LLC	Management Services	12,669
51	HUMPHREYS, DENISE C	Management Services	12,517
52	HYQUAL	Management Services	78,845
53	IDACORP INC	Management Services	81,866
54	INDUSTRIAL HYGIENE RESOURCES,	Management Services	24,606
55	INTERMOUNTAIN TECHNOLOGY GROUP	Computer Support Services	122,413
56	INTERWOVEN INC	Management Services	16,000
57	IOWA INSTITUTE OF HYDRAULICS	Engineering Services	79,336
58	JAY H HULET & HIS ATTORNEY	Legal Services	17,218
59	JBR ENVIRONMENTAL CONSULTANTS	Environmental Services	22,575
60	JUB ENGINEERS	Engineering Services	43,474
61	KPMG LLP	Management Services	85,000
62	LE BOEUF LAMB GREENE	Legal Services	1,851,491
63	MARSH ADVANTAGE AMERICA	Management Services	24,840
64	MCMILLEN & ASSOCIATE, INC.	Management Services	17,419
65	MCMILLEN ENGINEERING, LLC	Engineering Services	128,120
66	MCMILLIAN ELDRIDGE	Engineering Services	23,642
67	MILLER BATEMAN LLP	Legal Services	103,240
68	MOSAIC COMPANY	Information Security Service	56,500
69	MWH AMERICAS, INC.	Management Services	12,540
70	NAVIGANT CONSULTING INC	Consulting Services	15,000
71	NELSON & ASSOCIATES	Management Services	11,600
72	NEXUS ENERGY SOFTWARE	Computer Support Services	80,000
73	NIELSEN GROUP INC, THE	Consulting Services	245,112
74	NORTH COUNTRY RESOURCES, INC	Management Services	16,967
75	NORTH WIND, INC.	Management Services	39,412
76	NORTHWEST RESEARCH GROUP	Management Services	11,920
77	ORACLE	Computer Support Services	138,977
78	OSI SOFTWARE	Computer Support Services	46,900
79	PARR WADDOUPS BROWN GEE AND LO	Environmental Services	71,367
80	PEARL MEYER & PARTNERS	Management Services	84,630
81	PERKINS COIE LLP	Legal Services	147,387
82	PERSONNEL PLUS	Management Services	20,851
83	PGP CORPORATION	Management Services	21,250
84	PHONE PRO	Management Services	11,296
85	POWER ENGINEERS INC	Engineering Services	97,727
86	POWERCET CORPORATION	Management Services	10,028

STATE OF IDAHO - TOTAL SYSTEM DATA			
PROFESSIONAL OR CONSULTATIVE SERVICES - ITEMS \$10,000 AND OVER			
Line No.	PAYEE (a)	SERVICE TYPE (b)	Amount (c)
87	PUBLIC OPINION STRATEGIES LLC	Management Services	15,500
88	RAIN SHADOW RESEARCH, INC	Management Services	23,553
89	RAPIDIGM INC	Computer Support Services	41,179
90	RESOLVE, INC	Management Services	218,251
91	RIDDELL WILLIAMS P.S.	Legal Services	92,619
92	RIGHT SYSTEMS, INC	Management Services	11,315
93	RIPLEY, LARRY D	Legal Services	58,075
94	RIVERSIDE TECHNOLOGY INC	Management Services	269,010
95	ROBERT J RIETH	Legal Services	21,304
96	ROSEMARY BRENNAN CURTIN, INC	Management Services	23,121
97	SALLADAY & DAVIS	Legal Services	79,026
98	SCIENCE APPLICATIONS INTE	Environmental Services	18,189
99	SMITH, CURTIS D	Cloud Seeding Services	63,454
100	SOFTWARE AG INC	Computer Support Services	181,170
101	SPATIAL NETWORK SOLUTIONS	Management Services	38,340
102	SPL WORLDGROUP CONSULTING INC	Computer Support Services	51,136
103	SPL WORLDGROUP INC	Computer Support Services	11,446
104	STAHMAN, ROBERT W	Legal Services	171,650
105	STATE OF IDAHO FISH & GAME	Environmental Services	56,918
106	STATISTICAL DESIGN	Management Services	13,314
107	STEPTOE & JOHNSON LLP	Legal Services	334,590
108	STOEL RIVES LLP	Legal Services	24,876
109	STONE, R H	Management Services	78,045
110	STORAGETEK	Management Services	69,856
111	STRATA GEOTECH ENGINEERING	Engineering Services	14,998
112	SULLIVAN & CROMWELL	Legal Services	160,156
113	SWCA, INC	Environmental Services	10,513
114	TETRA TECH EM INC	Environmental Services	28,232
115	THORNTON CONSULTING	Management Services	11,679
116	TOWERS PERRIN HR SERVICES	Management Services	9,760
117	TREASURE VALLEY LEGAL SERVICES	Legal Services	69,591
118	TRUST ACCOUNT OF ALLEN & MCLAN	Legal Services	160,000
119	UNIVERSITY OF IDAHO	Environmental Services	94,348
120	UTILITY RESOURCES	Management Services	61,946
121	VAN NESS FELDMAN	Legal Services	542,035
122	WOOD CRAPO, LLC	Legal Services	10,001
123	YTURRI, ROSE, BURNHAM, BENTZ	Legal Services	17,259
124	ZGA ARCHITECTS & PLANNERS	Architectural Services	31,443

PROFESSIONAL OR CONSULTATIVE SERVICES			
<u>ITEMS \$5,000 OR MORE BUT LESS THAN \$10,000</u>			
Line No.	PAYEE	PREDOMINANT NATURE OF SERVICE	AMOUNT
1	ASCENTIUM	Consulting Services	\$ 5,412
2	ARMSTRONG PLANNING	Planning Service	6,180
3	E TRADE	Management Services	6,312
4	EMC CORPORATION	Technical Services	6,025
5	ENVINTA	Management Services	7,500
6	ENVIRONMENTAL ENGINEERING	Environmental Services	8,348
7	EPIS, INC	Management Services	7,500
8	EVANS KEENE	Management Services	5,452
9	FIRE CAUSE ANALYSIS	Engineering Services	5,478
10	GJORDING & FOUSER, PLLC	Management Services	7,621
11	HOPKINS RODEN CROCKET	Lobby Services	5,900
12	IDAHO SAND & GRAVEL	Engineering Services	5,000
13	INTERACTION CONSULTING	Management Services	9,138
14	INTERMOUNTAIN CLAIMS, INC	Investigation Services	6,692
15	JEFFREY H BRAATNE PHD	Medical Consulting	6,200
16	JONES, GLEDHILL, HESS, ANDREWS	Management Services	7,903
17	LITCHFIELD CONSULTING GROUP	Management Services	9,983
18	KEN MALGREN	Investigation Services	9,276
19	MILLIGAN PHD, JAMES	Medical Consulting	5,923
20	RW BECK	Legal Services	5,189
21	SMITHSONIAN INSTITUTE	Environmnetal Services	8,599
22	TERRACON	Management Services	5,081
23	TOWERS PERRIN HR SERVICES	Management Services	9,760
24	VAN WINKLE ENVIRONMENTAL CONSULT	Management Services	8,100
25	YR SERVICES	Management Services	6,022
26			
27			
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ELECTRIC PLANT IN SERVICE (Accounts 1

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

Line No.	Account (a)	Balance at Beginning of year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization.....	\$ 5,258	
3	(302) Franchises and Consents.....	9,375,034	
4	(303) Miscellaneous Intangible Plant.....	61,381,345	
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4).....	70,761,637	
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.....	2,558,441	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15).....	756,558,877	
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).....	594,274,308	
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.....		

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01, 102, 103 and 106)

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.
			\$ 62,945	(301)	1
			17,894,190	(302)	2
			46,383,713	(303)	3
			64,340,848		4
					5
					6
				(310)	7
				(311)	8
				(312)	9
				(313)	10
				(314)	11
				(315)	12
				(316)	13
			3,430,383	(317)	14
			779,416,892		15
					16
				(320)	17
				(321)	18
				(322)	19
				(323)	20
				(324)	21
				(325)	22
				(326)	23
					24
					25
				(330)	26
				(331)	27
				(332)	28
				(333)	29
				(334)	30
				(335)	31
				(336)	32
				(337)	33
			596,589,744		34
					35
				(340)	36
				(341)	37
				(342)	38
				(343)	39
				(344)	40
				(345)	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).....	\$ 49,549,572	
46	TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 45).....	1,400,382,756	
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights.....	18,967,406	
49	(352) Structures and Improvements.....	26,513,448	
50	(353) Station Equipment.....	192,783,834	
51	(354) Towers and Fixtures.....	65,195,492	
52	(355) Poles and Fixtures.....	74,353,999	
53	(356) Overhead Conductors and Devices.....	93,540,014	
54	(357) Underground Conduit.....		
55	(358) Underground Conductors and Devices.....		
56	(359) Roads and Trails.....	258,820	
57	(359.1) Asset Retirement Costs for Transmission Plant.....		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57).....	471,613,012	
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights.....	3,236,450	
61	(361) Structures and Improvements.....	17,558,946	
62	(362) Station Equipment.....	121,883,650	
63	(363) Storage Battery Equipment.....		
64	(364) Poles, Towers, and Fixtures.....	169,651,555	
65	(365) Overhead Conductors and Devices.....	87,163,932	
66	(366) Underground Conduit.....	38,597,249	
67	(367) Underground Conductors and Devices.....	145,041,107	
68	(368) Line Transformers.....	247,888,244	
69	(369) Services.....	43,848,501	
70	(370) Meters.....	45,244,916	
71	(371) Installations on Customer Premises.....	2,221,384	
72	(372) Leased Property on Customer Premises.....		
73	(373) Street Lighting and Signal Systems.....	3,761,277	
74	(374) Asset Retirement Costs for Distribution Plant.....		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74).....	926,097,210	
76	5. GENERAL PLANT		
77	(389) Land and Land Rights.....	7,893,724	
78	(390) Structures and Improvements.....	55,505,835	
79	(391) Office Furniture and Equipment.....	47,946,665	
80	(392) Transportation Equipment.....	40,408,870	
81	(393) Stores Equipment.....	928,294	
82	(394) Tools, Shop, and Garage Equipment.....	3,533,350	
83	(395) Laboratory Equipment.....	8,509,357	
84	(396) Power Operated Equipment.....	5,830,803	
85	(397) Communication Equipment.....	24,062,804	
86	(398) Miscellaneous Equipment.....	2,161,775	
87	SUBTOTAL (Enter Total of lines 77 thru 86).....	196,781,476	
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).....	196,781,476	
91	TOTAL (Accounts 101 and 106).....	3,065,636,092	
92	(102) Electric Plant Purchased.....		
93	(Less) (102) Electric Plant Sold.....		
94	(103) Experimental Plant Unclassified.....		
95			
96	TOTAL Electric Plant in Service.....	\$ 3,065,636,092	

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
			\$ 99,694,684		45
			1,475,701,320		46
					47
			21,047,463	(350)	48
			28,117,792	(352)	49
			199,533,892	(353)	50
			67,625,521	(354)	51
			76,407,981	(355)	52
			96,515,357	(356)	53
				(357)	54
				(358)	55
			259,238	(359)	56
				(359.1)	57
			489,507,245		58
					59
			6,719,974	(360)	60
			18,660,144	(361)	61
			129,980,459	(362)	62
				(363)	63
			174,103,722	(364)	64
			89,295,291	(365)	65
			40,992,386	(366)	66
			151,082,701	(367)	67
			266,919,861	(368)	68
			45,946,816	(369)	69
			48,247,223	(370)	70
			2,291,375	(371)	71
				(372)	72
			3,798,654	(373)	73
				(374)	74
			978,038,606		75
					76
			7,937,421	(389)	77
			56,620,933	(390)	78
			45,779,692	(391)	79
			43,849,209	(392)	80
			898,339	(393)	81
			3,842,719	(394)	82
			8,543,043	(395)	83
			6,700,450	(396)	84
			24,069,684	(397)	85
			2,419,657	(398)	86
			200,661,147		87
				(399)	88
				(399.1)	89
			200,661,147		90
			3,208,249,165		91
				(102)	92
				(102)	93
				(371)	94
					95
			\$ 3,208,249,165		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.....	\$ 289,325,450	\$ 264,432,685
3	(442) Commercial and Industrial Sales		
4	Small (or Commercial)(See Instr. 4) (1).....	237,308,467	237,670,029
5	Large (or Industrial)(See Instr. 4) (2).....	107,515,732	103,211,741
6	(444) Public Street and Highway Lighting.....	2,312,403	2,194,234
7	(445) Other Sales to Public Authorities.....		
8	(446) Sales to Railroads and Railways.....		
9	(448) Interdepartmental Sales.....		
10	TOTAL Sales to Ultimate Consumers.....	636,462,052 *	607,508,689
11	(447) Sales for Resale - Opportunity...Non-Firm Only.....	130,947,067	110,451,320
12	TOTAL Sales of Electricity.....	767,409,119	717,960,009
13	(449.1) Provision for Rate Refunds.....	400,102	1,114,364
14	TOTAL Revenue Net of Provision for Refunds.....	767,809,221	719,074,373
15	Other Operating Revenues		
16	(450) Forfeited Discounts.....		
17	(451) Miscellaneous Service Revenues.....	5,415,794	4,177,891
18	(453) Sales of Water and Water Power.....		
19	(454) Rent from Electric Property.....	15,930,432	16,096,192
20	(455) Interdepartmental Rents.....		
21	(456) Other Electric Revenues.....	13,758,967	17,430,881
22			
23			
24			
25	TOTAL Other Operating Revenues.....	35,105,192	37,704,963
26	TOTAL Electric Operating Revenues.....	\$ 802,914,413	\$ 756,779,337

(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		Line No.
Amount for Current Year (d)	Amount for Previous Year (e)	Amount for Current Year (f)	Number for Previous Year (g)	
4,569,022,693	4,389,994,071	360,484	347,384	1
				2
				3
4,880,517,406	5,092,937,686	69,642	67,638	4
3,135,239,312	3,064,574,997	121	112	5
27,802,162	27,037,680	619	480	6
				7
				8
				9
12,612,581,573 **	12,574,544,434	430,866	415,614	10
2,611,581,658	2,717,422,630	N/A	N/A	11
15,224,163,231	15,291,967,064	430,866	415,614	12
				13
* Includes \$ 4,256,023 unbilled revenues. ** Includes 45,901,297 KWH relating to unbilled revenues. Lines 11 through 21 are on an "allocated" basis.				

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES			
If the amount for previous year is not derived from previously reported figures, explain in footnotes.			
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering.....	\$ 1,206,279	\$ 1,121,417
5	(501) Fuel.....	93,196,241	92,660,616
6	(502) Steam Expenses.....	6,492,450	5,029,304
7	(503) Steam from Other Sources.....		
8	(Less) (504) Steam Transferred-Cr.....		
9	(505) Electric Expenses.....	1,516,621	1,470,502
10	(506) Miscellaneous Steam Power Expenses.....	6,415,549	5,543,638
11	(507) Rents.....	307,012	671,368
12	(509) Allowances.....		
13	TOTAL Operation (Enter Total of lines 4 thru 12).....	109,134,153	106,496,845
14	Maintenance		
15	(510) Maintenance Supervision and Engineering.....	2,011,225	2,701,548
16	(511) Maintenance of Structures.....	398,053	338,935
17	(512) Maintenance of Boiler Plant.....	14,928,572	11,943,969
18	(513) Maintenance of Electric Plant.....	5,283,963	4,886,517
19	(514) Maintenance of Miscellaneous Steam Plant.....	1,171,554	2,905,848
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19).....	23,793,367	22,776,817
21	TOTAL Power Production Expenses-Steam Power (Enter Total of lines 13 and 20)....	132,927,521	129,273,662
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.....	4,301,903	4,176,063
45	(536) Water for Power.....	4,028,245	3,794,616
46	(537) Hydraulic Expenses.....	7,707,802	6,416,142
47	(538) Electric Expenses.....	1,193,152	1,175,791
48	(539) Miscellaneous Hydraulic Power Generation Expenses.....	1,788,748	2,388,132
49	(540) Rents.....	339,221	358,887
50	TOTAL Operation (Enter Total of lines 44 thru 49).....	19,359,072	18,309,631

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.....	\$ 1,204,479	\$ 999,707
54	(542) Maintenance of Structures.....	849,491	949,154
55	(543) Maintenance of Reservoirs, Dams, and Waterways.....	645,746	975,013
56	(544) Maintenance of Electric Plant.....	2,326,595	2,140,578
57	(545) Maintenance of Miscellaneous Hydraulic Plant.....	2,695,213	2,495,950
58	TOTAL Maintenance (Enter Total of lines 53 thru 57).....	7,721,523	7,560,401
59	TOTAL Power Production Expenses-Hydraulic Power (Enter Total of lines 50 and 58)...	27,080,595	25,870,033
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering.....	368,857	370,143
63	(547) Fuel.....	3,937,048	4,590,362
64	(548) Generation Expenses.....	218,019	161,183
65	(549) Miscellaneous Other Power Generation Expenses.....	316,913	282,385
66	(550) Rents.....	6,363	-
67	TOTAL Operation (Enter Total of lines 62 thru 66).....	4,847,200	5,404,073
68	Maintenance		
69	(551) Maintenance Supervision and Engineering.....	183	217
70	(552) Maintenance of Structures.....	241,128	117,034
71	(553) Maintenance of Generating and Electric Plant.....	28,556	65,273
72	(554) Maintenance of Miscellaneous Other Power Generation Plant.....	404,791	227,653
73	TOTAL Maintenance (Enter Total of lines 69 thru 72).....	674,659	410,177
74	TOTAL Power Production Expenses-Other Power (Enter Total of lines 67 and 73).....	5,521,859	5,814,251
75	E. Other Power Supply Expenses		
76	(555) Purchased Power.....	209,322,905	184,262,619
77	(556) System Control and Load Dispatching.....	73,156	100,474
78	(557) Other Expenses.....	(966,244)	38,808,432
79	TOTAL Other Power Supply Expenses (Enter Total of lines 76 thru 78).....	208,429,817	223,171,525
80	TOTAL Power Production Expenses (Enter Total of lines 21, 41, 59, 74, and 79).....	373,959,791	384,129,470
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering.....	1,698,144	1,709,826
84	(561) Load Dispatching.....	2,539,804	2,482,481
85	(562) Station Expenses.....	1,346,029	1,423,846
86	(563) Overhead Line Expenses.....	432,874	456,328
87	(564) Underground Line Expenses.....		
88	(565) Transmission of Electricity by Others.....	7,209,525	7,950,494
89	(566) Miscellaneous Transmission Expenses.....	251,009	15,028
90	(567) Rents.....	1,320,471	1,832,087
91	TOTAL Operation (Enter Total of lines 83 thru 90).....	14,797,857	15,870,090
92	Maintenance		
93	(568) Maintenance Supervision and Engineering.....	586,972	549,772
94	(569) Maintenance of Structures.....	57,860	-
95	(570) Maintenance of Station Equipment.....	2,274,825	2,541,620
96	(571) Maintenance of Overhead Lines.....	1,603,680	1,976,089
97	(572) Maintenance of Underground Lines.....		
98	(573) Maintenance of Miscellaneous Transmission Plant.....	13,871	6,631
99	TOTAL Maintenance (Enter Total of lines 93 thru 98).....	4,537,207	5,074,111
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99).....	19,335,065	20,944,202
101	3. DISTRIBUTION EXPENSES		
102	Operation		
103	(580) Operation Supervision and Engineering.....	3,592,185	3,368,098

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES			
If the amount for previous year is not derived from previously reported figures, explain in footnotes.			
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
104	3. DISTRIBUTION EXPENSES (Continued)		
105	(581) Load Dispatching.....	\$ 2,385,842	\$ 2,253,438
106	(582) Station Expenses.....	887,177	891,829
107	(583) Overhead Line Expenses.....	2,726,164	3,194,716
108	(584) Underground Line Expenses.....	1,703,802	1,640,328
109	(585) Street Lighting and Signal System Expenses.....	114,536	143,396
110	(586) Meter Expenses.....	3,934,241	3,935,551
111	(587) Customer Installations Expenses.....	692,207	487,909
112	(588) Miscellaneous Distribution Expenses.....	4,300,696	4,664,454
113	(589) Rents.....	147,491	140,393
114	TOTAL Operation (Enter Total of lines 103 thru 113).....	20,484,342	20,720,112
115	Maintenance		
116	(590) Maintenance Supervision and Engineering.....	85,167	62,175
117	(591) Maintenance of Structures.....	64,820	-
118	(592) Maintenance of Station Equipment.....	2,468,821	2,752,978
119	(593) Maintenance of Overhead Lines.....	10,039,765	10,219,142
120	(594) Maintenance of Underground Lines.....	1,090,650	1,222,685
121	(595) Maintenance of Line Transformers.....	292,049	235,963
122	(596) Maintenance of Street Lighting and Signal Systems.....	359,616	468,812
123	(597) Maintenance of Meters.....	740,287	909,523
124	(598) Maintenance of Miscellaneous Distribution Plant.....	215,370	166,351
125	TOTAL Maintenance (Enter Total of lines 116 thru 124).....	15,356,544	16,037,629
126	TOTAL Distribution Expenses (Enter Total of lines 114 and 125).....	35,840,885	36,757,741
127	4. CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision.....	471,754	408,079
130	(902) Meter Reading Expenses.....	4,449,433	4,489,463
131	(903) Customer Records and Collection Expenses.....	8,922,800	8,910,379
132	(904) Uncollectible Accounts.....	1,389,879	2,850,386
133	(905) Miscellaneous Customer Accounts Expenses.....	26,596	(5,776)
134	TOTAL Customer Accounts Expenses (Enter Total of lines 129 thru 133).....	15,260,462	16,652,531
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision.....	273,766	306,135
138	(908) Customer Assistance Expenses.....	8,354,446	7,174,632
139	(909) Informational and Instructional Expenses.....	0	5,299
140	(910) Miscellaneous Customer Service and Informational Expenses.....	743,988	715,731
141	TOTAL Cust. Service and Informational Expenses (Enter Total of lines 137 thru 140).....	9,372,200	8,201,797
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.....	37,712,128	42,139,149
152	(921) Office Supplies and Expenses.....	15,031,267	13,713,290
153	(Less) (922) Administrative Expenses Transferred-Credit.....	(22,062,446)	(24,555,748)

**STATE OF IDAHO - ALLOCATED
An Original**

Idaho Power Company

December 31, 2005

ELECTRIC OPERATION AND MAINTENANCE EXPENSES			
If the amount for previous year is not derived from previously reported figures, explain in footnotes.			
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
154	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
155	(923) Outside Services Employed.....	\$ 7,296,517	\$ 6,574,191
156	(924) Property Insurance.....	2,662,273	2,979,099
157	(925) Injuries and Damages.....	5,326,569	5,585,966
158	(926) Employee Pensions and Benefits.....	21,409,065	24,852,207
159	(927) Franchise Requirements.....	2,300	2,075
160	(928) Regulatory Commission Expenses.....	3,335,147	3,301,815
161	(929) Duplicate Charges-Cr.....		
162	(930.1) General Advertising Expenses.....	112,265	110,224
163	(930.2) Miscellaneous General Expenses.....	1,731,007	1,825,509
164	(931) Rents.....	3,506	11,331
165	TOTAL Operation (Enter Total of lines 151 thru 164).....	72,559,597	76,539,107
166	Maintenance		
167	(935) Maintenance of General Plant.....	3,204,656	2,328,674
168	TOTAL Admin and General Expenses (Enter Total of lines 165-167).....	75,764,253	78,867,780
169	TOTAL Elec Op and Maint Exp (Total of 80, 100, 126, 134, 141, 148, 168).....	\$ 529,532,657	\$ 545,553,521

IDAHO ONLY

NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES			
<p>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.</p> <p>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.</p> <p>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.</p>			
	December 31, 2005	December 31, 2004	
1 Payroll Period Ended (Date).....			
2 Total Regular Full-Time Employees.....	1,774	1,757	
3 Total Part-Time and Temporary Employees.....	29	45	
4 Total Employees.....	1,803	1,802	