THIS FILING IS (CHECK ONE BOX FOR EACH ITEM)			
Item 1: ☒	An Initial (Original) Submission	OR ☐	Resubmission No. ____
Item 2: ☐	An Original Signed Form	OR ☐	Conformed Copy

Form Approved
OMB No. 1902-0021
(Expires 3/31/2005)

FERC Form No. 1:
ANNUAL REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHERS

This report is mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1. 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 this report to be of a confidential nature.

Exact Legal Name of Respondent (Company)	Year of Report
Idaho Power Company	**Dec. 31,** 2002

INSTRUCTIONS FOR FILING THE
FERC FORM NO. 1

GENERAL INFORMATION

I. Purpose

This form is a regulatory support requirement (18 CFR 141.1). It is designed to collect financial and operational information from major electric utilities, Licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. This report is also secondarily considered to be a nonconfidential public use form supporting a statistical publication (Financial Statistics of Selected Electric Utilities), published by the Energy Information Administration.

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 this form.

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

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

III. What and Where to Submit

(a) Submit this form electronically through the Form 1 Submission Software and an original and six (6) conformed paper copies, properly filed in and attested, to:

Office of the Secretary
Federal Energy Regulatory Commission
888 First Street, NE.
Room 1A
Washington, DC 20426

Retain one copy of this report for your files.

Include with the original and each conformed paper copy of this form the subscription statement required by 18 C.F.R. 385.2011(c)(5). Paragraph (c)(5) of 18 C.F.R. 385.2011 requires each respondent submitting data electronically to file a subscription stating that the paper copies contain the same information as the electronic filing, that the signer knows the contents of the paper copies and electronic filing, and that the contents as stated in the copies and electronic filing are true to the best knowledge and belief of the signer.

(b) 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 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:

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

(c) For the CPA certification, submit with the original submission, or within 30 days after the filing date for this form, 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) 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 41.10-41.12 for specific qualifications.)

III. What and Where to Submit (Continued)
(c) Continued

Schedules	Reference 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

When accompanying this form, 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 office of the Secretary at the address indicated at III (a).

Use the following format 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.

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 ES-1
Washington, DC 20426
(202) 208-2474

IV. When to Submit

Submit this report form on or before April 30th of the year following the year covered by this report.

V. Where to Send Comments on Public Reporting Burden

The public reporting burden for this collection of information is estimated to average 1,217 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. Send comments regarding this burden estimate or any aspect of this collection of information, including suggestions for reducing this burden, to the Federal Energy Regulatory Commission, 888 First Street N.E., Washington, DC 20426 (Attention: Mr. Michael Miller, CI-1); 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 this 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 year, and use for statement of income accounts the current year's amounts.

III. Complete each question fully and accurately, even if it has been answered in a previous annual 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, 3, and 4.

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). The date of the resubmission must be reported in the header for all form pages, whether or not they are changed from the previous filing.

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 Submission Software and an original and six (6) conformed paper copies of the entire form, as well as the appropriate number of copies of the subscription statement indicated at instruction III (a). Resubmissions must be numbered sequentially on the cover page of the paper copies of the form. In addition, the cover page of each paper copy must indicate that the filing is a resubmission. Send the resubmissions to the address indicated at instruction III (a).

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

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

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

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the proper administration of this Act. The Commission my prescribe the manner and form in which such reports shalt 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."

"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 filed..."

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:
ANNUAL REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent	02 Year of Report
Idaho Power Company	Dec. 31, 2002

03 Previous Name and Date of Change *(if name changed during year)*

/ /

04 Address of Principal Office at End of Year *(Street, City, State, Zip Code)*

1221 W Idaho Street, P.O. Box 70 Boise, ID 83707-0070

05 Name of Contact Person	06 Title of Contact Person
Darrel Anderson	VP, CFO & Treasurer

07 Address of Contact Person *(Street, City, State, Zip Code)*

1221 W Idaho Street, P.O. Box 70 Boise, ID 83707-0070

08 Telephone of Contact Person, *Including Area Code*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(208) 388-2650	(1) ☒ An Original (2) ☐ A Resubmission	04/30/2003

ATTESTATION

The undersigned officer certifies that he/she has examined the accompanying report: that to the best of his/her knowledge, information, and belief, all statements of fact contained in the accompanying report are true and the accompanying report is a correct statement of the business and affairs of the above named respondent in respect to each and every matter set forth therein during the period from and including January 1 to and including December 31 of the year of the report.

01 Name	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Darrel Anderson		04/30/2003
02 Title		
VP, CFO & Treasurer		

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.

LIST OF SCHEDULES (Electric Utility)

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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	Electric Energy Account	401	
54	Monthly Peaks and Output	401	
55	Steam Electric Generating Plant Statistics (Large Plants)	402-403	
56	Hydroelectric Generating Plant Statistics (Large Plants)	406-407	
57	Pumped Storage Generating Plant Statistics (Large Plants)	408-409	None
58	Generating Plant Statistics (Small Plants)	410-411	
59	Transmission Line Statistics	422-423	
60	Transmission Lines Added During Year	424-425	
61	Substations	426-427	
62	Footnote Data	450	
	Stockholders' Reports Check appropriate box: [X] Four copies will be submitted [ ] No annual report to stockholders is prepared		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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 Vice President, CFO and Treasurer, Idaho Power Company
1221 W. Idaho Street, P.O. Box 70, Boise, Idaho 83707-0070

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

Idaho, June 30, 1989

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

Not Applicable

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

Class of Utility Service	State
Electric	Idaho
"	Oregon

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

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

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report *(Mo, Da, Yr)* 04/30/2003	Year of Report Dec. 31, 2002

CONTROL OVER RESPONDENT

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

Idaho Power Company is a subsidiary of IdaCorp.

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

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

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		
4				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1			
2	President and Chief Executive Officer	Jan B. Packwood	580,000
3			
4	Executive Vice President, Marketing & Sales	Richard Riazzi (1)	46,154
5			
6	President and Chief Operation Officer	J. LaMont Keen	350,000
7			
8	Vice President, General Counsel and Secretary	Robert W. Stahman	200,000
9			
10	Sr Vice President, Delivery	James C. Miller	250,000
11			
12	Vice President, Chief Finance Officer and Treasurer	Darrel T Anderson	185,000
13			
14	Vice President, Corporate Services	Clifford N. Olson (2)	152,000
15			
16	Vice President , Power Supply	John P Prescott	174,000
17			
18	Vice President, Human Resources	Marlene K Williams	159,000
19			
20	Vice President and Chief Information Officer	Bryan A Kearny	183,000
21			
22	Vice President, Regulatory Affairs	Ric Gale	140,000
23			
24	Vice President, Public Affairs	Greg Panter	138,000
25			
26			
27			
28			
29	(1) Moved to subsidiary Company 2-1-2002		
30			
31	(2) Retired December 2002		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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		
4	Roger L. Breezley (1)	Breezley Investments, 3625 U.S. Bancorp Tower,
5		Portland, Oregon 97208
6		
7	John B. Carley ***	2375 N. Towerview Lane, Boise, Idaho 83702
8		
9		
10		
11	Jack K. Lemley ***	Lemley & Associates, Inc.
12		1508 N. 13th, Boise, Idaho 83702
13		
14	Evelyn Loveless	Global, Inc., 900 W. Jefferson Street, Boise, Idaho 83702
15		
16	Gary Michael	P.O. Box 1718 Boise Idaho 83701
17		
18	Jon H. Miller, Chairman of the Board***	P.O. Box 1557, Boise, Idaho 83701
19		
20	Peter S. O'Neill	O'Neill Enterprises, Inc.
21		871 E. Parkcenter Blvd., Boise, Idaho 83706
22		
23	Jan B. Packwood President and CEO **	Idaho Power Company, 1221 W. Idaho Street,
24		P.O. Box 70, Boise, Idaho 83707-0070
25		
26	Robert A. Tinstman ***	4433 W. Quail Point Court, Boise, Idaho, 83703
27		
28	Christopher L. Culp	1400 North Lake Shore Drive,#8B, Chicago, IL 60610
29		
30		
31		
32		
33	(1) Retired August 2002.	
34		
35		
36		
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48		

IMPORTANT CHANGES DURING THE 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.

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

1. None

2. None

3. None

4. None

5. None

6.$100 million of 4.75% First Mortgage Bonds maturing 11/15/12, issued 11/15/02 under OPUC UF 4181,Order No 01-817 Wyoming Docket #20005-ES-01-23,Record No.6838 and IPUC Case #ICP-E-01-27, Order No. 28848.

$100 million of 6.00% First Mortgage Bonds maturing 11/15/12, issued 11/15/02 under OPUC UF 4181,Order No 01-817 Wyoming Docket #20005-ES-01-23,Record No.6838 and IPUC Case #ICP-E-01-27, Order No. 28848.

7. None

8. On December 29, 2002 a 3% General Wage Increase

9. See pages 123.9 through 123.14

10. None

11. None

12. None

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	2,991,861,487	3,089,299,722
3	Construction Work in Progress (107)	200-201	86,009,543	92,481,654
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		3,077,871,030	3,181,781,376
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 111, 115)	200-201	1,220,002,130	1,294,961,078
6	Net Utility Plant (Enter Total of line 4 less 5)		1,857,868,900	1,886,820,298
7	Nuclear Fuel (120.1-120.4, 120.6)	202-203	0	0
8	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
9	Net Nuclear Fuel (Enter Total of line 7 less 8)		0	0
10	Net Utility Plant (Enter Total of lines 6 and 9)		1,857,868,900	1,886,820,298
11	Utility Plant Adjustments (116)	122	0	0
12	Gas Stored Underground - Noncurrent (117)		0	0
13	**OTHER PROPERTY AND INVESTMENTS**			
14	Nonutility Property (121)	221	1,388,096	1,050,389
15	(Less) Accum. Prov. for Depr. and Amort. (122)		0	0
16	Investments in Associated Companies (123)		0	0
17	Investment in Subsidiary Companies (123.1)	224-225	12,574,662	15,107,633
18	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
19	Noncurrent Portion of Allowances	228-229	0	0
20	Other Investments (124)		67,616	26,881
21	Special Funds (125-128)		255,212	20,968,704
22	TOTAL Other Property and Investments (Total of lines 14-17,19-21)		14,285,586	37,153,607
23	**CURRENT AND ACCRUED ASSETS**			
24	Cash (131)		5,543,687	4,974,739
25	Special Deposits (132-134)		0	0
26	Working Fund (135)		36,935	82,849
27	Temporary Cash Investments (136)		37,416,187	7,599,409
28	Notes Receivable (141)		9,761,917	12,637,655
29	Customer Accounts Receivable (142)		58,702,410	56,947,245
30	Other Accounts Receivable (143)		2,259,483	2,694,112
31	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		1,500,000	1,566,346
32	Notes Receivable from Associated Companies (145)		33,686,906	21,827,722
33	Accounts Receivable from Assoc. Companies (146)		3,830,298	6,077,134
34	Fuel Stock (151)	227	8,726,387	6,942,920
35	Fuel Stock Expenses Undistributed (152)	227	0	0
36	Residuals (Elec) and Extracted Products (153)	227	0	0
37	Plant Materials and Operating Supplies (154)	227	20,705,724	18,938,667
38	Merchandise (155)	227	0	0
39	Other Materials and Supplies (156)	227	0	0
40	Nuclear Materials Held for Sale (157)	202-203/227	0	0
41	Allowances (158.1 and 158.2)	228-229	0	0
42	(Less) Noncurrent Portion of Allowances		0	0
43	Stores Expense Undistributed (163)	227	2,573,824	2,519,780
44	Gas Stored Underground - Current (164.1)		0	0
45	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
46	Prepayments (165)		31,897,278	32,818,565
47	Advances for Gas (166-167)		0	0
48	Interest and Dividends Receivable (171)		21,101	7,514
49	Rents Receivable (172)		0	0
50	Accrued Utility Revenues (173)		37,400,421	35,713,885
51	Miscellaneous Current and Accrued Assets (174)		0	0
52	Derivative Instrument Assets (175)		0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
53	Derivative Instrument Assets - Hedges (176)		0	0
54	TOTAL Current and Accrued Assets (Enter Total of lines 24 thru 53)		251,062,558	208,215,850
55	**DEFERRED DEBITS**			
56	Unamortized Debt Expenses (181)		6,346,670	5,067,201
57	Extraordinary Property Losses (182.1)	230	0	0
58	Unrecovered Plant and Regulatory Study Costs (182.2)	230	0	0
59	Other Regulatory Assets (182.3)	232	599,241,273	499,305,339
60	Prelim. Survey and Investigation Charges (Electric) (183)		90,719	91,668
61	Prelim. Sur. and Invest. Charges (Gas) (183.1, 183.2)		0	0
62	Clearing Accounts (184)		-33,501	-272,774
63	Temporary Facilities (185)		0	0
64	Miscellaneous Deferred Debits (186)	233	105,580,011	97,170,248
65	Def. Losses from Disposition of Utility Plt. (187)		0	0
66	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
67	Unamortized Loss on Reaquired Debt (189)		10,583,354	11,795,673
68	Accumulated Deferred Income Taxes (190)	234	40,575,302	36,905,119
69	Unrecovered Purchased Gas Costs (191)		0	0
70	TOTAL Deferred Debits (Enter Total of lines 56 thru 69)		762,383,828	650,062,474
71	TOTAL Assets and Other Debits (Enter Total of lines 10,11,12,22,54,70)		2,885,600,872	2,782,252,229

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
1	**PROPRIETARY CAPITAL**			
2	Common Stock Issued (201)	250-251	94,030,878	94,030,878
3	Preferred Stock Issued (204)	250-251	104,387,200	53,392,700
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	361,837,614	361,824,690
7	Other Paid-In Capital (208-211)	253	-2,954,854	123,232
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	4,143,734	2,710,115
11	Retained Earnings (215, 215.1, 216)	118-119	307,533,744	317,609,678
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	9,322,512	12,690,634
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Accumulated Other Comprehensive Income (219)	122(a)(b)	0	-7,109,123
15	TOTAL Proprietary Capital (Enter Total of lines 2 thru 13)		870,013,360	829,852,574
16	**LONG-TERM DEBT**			
17	Bonds (221)	256-257	797,460,000	920,460,000
18	(Less) Reaquired Bonds (222)	256-257	0	0
19	Advances from Associated Companies (223)	256-257	0	0
20	Other Long-Term Debt (224)	256-257	32,847,509	32,769,728
21	Unamortized Premium on Long-Term Debt (225)		0	0
22	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		1,029,295	2,405,047
23	TOTAL Long-Term Debt (Enter Total of lines 16 thru 21)		829,278,214	950,824,681
24	**OTHER NONCURRENT LIABILITIES**			
25	Obligations Under Capital Leases - Noncurrent (227)		0	0
26	Accumulated Provision for Property Insurance (228.1)		0	0
27	Accumulated Provision for Injuries and Damages (228.2)		1,500,000	1,936,041
28	Accumulated Provision for Pensions and Benefits (228.3)		2,520,328	1,847,824
29	Accumulated Miscellaneous Operating Provisions (228.4)		1,036,253	12,015,187
30	Accumulated Provision for Rate Refunds (229)		0	0
31	TOTAL OTHER Noncurrent Liabilities (Enter Total of lines 24 thru 29)		5,056,581	15,799,052
32	**CURRENT AND ACCRUED LIABILITIES**			
33	Notes Payable (231)		282,000,000	10,500,000
34	Accounts Payable (232)		108,545,330	51,827,939
35	Notes Payable to Associated Companies (233)		3,203,999	2,652,612
36	Accounts Payable to Associated Companies (234)		6,931,117	52,040
37	Customer Deposits (235)		157,453	1,185,637
38	Taxes Accrued (236)	262-263	-15,067,246	84,172,122
39	Interest Accrued (237)		12,891,444	12,399,447
40	Dividends Declared (238)		44,378	655
41	Matured Long-Term Debt (239)		0	0
42	Matured Interest (240)		0	0
43	Tax Collections Payable (241)		788,787	848,562
44	Miscellaneous Current and Accrued Liabilities (242)		15,916,801	21,628,365
45	Obligations Under Capital Leases-Current (243)		0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)(Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Balance at Beginning of Year (c)	Balance at End of Year (d)
46	Derivative Instrument Liabilities (244)		0	91,235
47	Derivative Instrument Liabilities - Hedges (245)		0	0
48	TOTAL Current & Accrued Liabilities (Enter Total of lines 32 thru 44)		415,412,063	185,358,614
49	**DEFERRED CREDITS**			
50	Customer Advances for Construction (252)		11,025,745	10,505,595
51	Accumulated Deferred Investment Tax Credits (255)	266-267	68,015,922	67,559,611
52	Deferred Gains from Disposition of Utility Plant (256)		0	0
53	Other Deferred Credits (253)	269	46,815,756	50,367,124
54	Other Regulatory Liabilities (254)	278	45,940,464	46,687,332
55	Unamortized Gain on Reaquired Debt (257)		0	0
56	Accumulated Deferred Income Taxes (281-283)	272-277	594,042,767	625,297,646
57	TOTAL Deferred Credits (Enter Total of lines 47 thru 53)		765,840,654	800,417,308
58			0	0
59			0	0
60			0	0
61			0	0
62			0	0
63			0	0
64			0	0
65			0	0
66			0	0
67			0	0
68			0	0
69			0	0
70			0	0
71	TOTAL Liab and Other Credits (Enter Total of lines 14,22,30,45,54)		2,885,600,872	2,782,252,229

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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 02 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 pages 122-123 for important notes regarding the statement 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 the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power and gas purchases.
6. Give concise explanations concerning significant amounts of any refunds made or received during the year

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	300-301	867,047,420	912,311,553
3	Operating Expenses			
4	Operation Expenses (401)	320-323	566,346,327	659,681,485
5	Maintenance Expenses (402)	320-323	54,599,254	55,876,578
6	Depreciation Expense (403)	336-337	85,193,315	80,689,086
7	Amort. & Depl. of Utility Plant (404-405)	336-337	8,519,658	6,673,063
8	Amort. of Utility Plant Acq. Adj. (406)	336-337	-22,723	-22,723
9	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)			
10	Amort. of Conversion Expenses (407)			
11	Regulatory Debits (407.3)			
12	(Less) Regulatory Credits (407.4)			
13	Taxes Other Than Income Taxes (408.1)	262-263	19,952,735	19,693,396
14	Income Taxes - Federal (409.1)	262-263	75,166,820	-52,618,236
15	- Other (409.1)	262-263	9,726,454	-14,479,363
16	Provision for Deferred Income Taxes (410.1)	234, 272-277	27,310,757	126,997,151
17	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	114,691,926	48,412,782
18	Investment Tax Credit Adj. - Net (411.4)	266	-456,312	1,966,044
19	(Less) Gains from Disp. of Utility Plant (411.6)			194,097
20	Losses from Disp. of Utility Plant (411.7)		12,328	12,328
21	(Less) Gains from Disposition of Allowances (411.8)		93,955	116,843
22	Losses from Disposition of Allowances (411.9)			
23	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 22)		731,562,732	835,745,087
24	Net Util Oper Inc (Enter Tot line 2 less 23) Carry fwd to P117,line 25		135,484,688	76,566,466

STATEMENT OF INCOME FOR THE YEAR (Continued)

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.

7. If any notes appearing in the report to stockholders are applicable to this Statement of Income, such notes may be included on pages 122-123.

B. Enter on pages 122-123 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 approximate dollar effect of such changes.

9. Explain in a footnote if the previous year's figures are different from that reported in prior reports.

10. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles, lines 2 to 23, and report the information in the blank space on pages.122-123 or in a footnote.

ELECTRIC UTILITY Current Year (e)	ELECTRIC UTILITY Previous Year (f)	GAS UTILITY Current Year (g)	GAS UTILITY Previous Year (h)	OTHER UTILITY Current Year (i)	OTHER UTILITY Previous Year (j)	Line No.
						1
867,047,420	912,311,553					2
						3
566,346,327	659,681,485					4
54,599,254	55,876,578					5
85,193,315	80,689,086					6
8,519,658	6,673,063					7
-22,723	-22,723					8
						9
						10
						11
						12
19,952,735	19,693,396					13
75,166,820	-52,618,236					14
9,726,454	-14,479,363					15
27,310,757	126,997,151					16
114,691,926	48,412,782					17
-456,312	1,966,044					18
	194,097					19
12,328	12,328					20
93,955	116,843					21
						22
731,562,732	835,745,087					23
135,484,688	76,566,466					24

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

STATEMENT OF INCOME FOR THE YEAR (Continued)

Line No.	OTHER UTILITY		OTHER UTILITY		OTHER UTILITY	
	Current Year (k)	Previous Year (l)	Current Year (m)	Previous Year (n)	Current Year (o)	Previous Year (p)
1						
2						
3						
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23						
24						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

STATEMENT OF INCOME FOR THE YEAR (Continued)

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
25	Net Utility Operating Income (Carried forward from page 114)		135,484,688	76,566,466
26	Other Income and Deductions			
27	Other Income			
28	Nonutilty Operating Income			
29	Revenues From Merchandising, Jobbing and Contract Work (415)		1,992,219	1,889,291
30	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		1,871,836	1,806,575
31	Revenues From Nonutility Operations (417)			
32	(Less) Expenses of Nonutility Operations (417.1)		2,764,304	9,399
33	Nonoperating Rental Income (418)		-1,768	-8,182
34	Equity in Earnings of Subsidiary Companies (418.1)	119	10,368,122	6,893,568
35	Interest and Dividend Income (419)		3,148,119	4,342,243
36	Allowance for Other Funds Used During Construction (419.1)		333,060	752,108
37	Miscellaneous Nonoperating Income (421)		2,203,829	91,622,074
38	Gain on Disposition of Property (421.1)		-329,175	871,309
39	TOTAL Other Income (Enter Total of lines 29 thru 38)		13,078,266	104,546,437
40	Other Income Deductions			
41	Loss on Disposition of Property (421.2)		2,678	19,029
42	Miscellaneous Amortization (425)	340		
43	Miscellaneous Income Deductions (426.1-426.5)	340	2,715,164	3,600,701
44	TOTAL Other Income Deductions (Total of lines 41 thru 43)		2,717,842	3,619,730
45	Taxes Applic. to Other Income and Deductions			
46	Taxes Other Than Income Taxes (408.2)	262-263	39,656	-9,987
47	Income Taxes-Federal (409.2)	262-263	-5,679,551	10,237,523
48	Income Taxes-Other (409.2)	262-263	-1,128,109	1,935,300
49	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	1,695,784	26,070,988
50	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	-3,878,547	1,876,330
51	Investment Tax Credit Adj.-Net (411.5)			
52	(Less) Investment Tax Credits (420)			
53	TOTAL Taxes on Other Income and Deduct. (Total of 46 thru 52)		-1,193,673	36,357,494
54	Net Other Income and Deductions (Enter Total lines 39, 44, 53)		11,554,097	64,569,213
55	Interest Charges			
56	Interest on Long-Term Debt (427)		51,127,383	55,704,367
57	Amort. of Debt Disc. and Expense (428)		964,219	1,027,776
58	Amortization of Loss on Reaquired Debt (428.1)		1,417,179	1,312,943
59	(Less) Amort. of Premium on Debt-Credit (429)			
60	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)			
61	Interest on Debt to Assoc. Companies (430)	340	652,515	843,507
62	Other Interest Expense (431)	340	6,331,567	7,745,906
63	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		2,374,774	3,736,839
64	Net Interest Charges (Enter Total of lines 56 thru 63)		58,118,089	62,897,660
65	Income Before Extraordinary Items (Total of lines 25, 54 and 64)		88,920,696	78,238,019
66	Extraordinary Items			
67	Extraordinary Income (434)			
68	(Less) Extraordinary Deductions (435)			
69	Net Extraordinary Items (Enter Total of line 67 less line 68)			
70	Income Taxes-Federal and Other (409.3)	262-263		
71	Extraordinary Items After Taxes (Enter Total of line 69 less line 70)			
72	Net Income (Enter Total of lines 65 and 71)		88,920,696	78,238,019

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

STATEMENT OF RETAINED EARNINGS FOR THE YEAR

1. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
2. 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)
3. State the purpose and amount of each reservation or appropriation of retained earnings.
4. 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.
5. Show dividends for each class and series of capital stock.
6. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
7. 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.
8. 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)	Amount (c)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)		
1	Balance-Beginning of Year		305,989,778
2	Changes		
3	Adjustments to Retained Earnings (Account 439)		
4			
5	Retirement of Flexible Auction Preferred Stock	216	-711,555
6			
7			
8			
9	TOTAL Credits to Retained Earnings (Acct. 439)		-711,555
10			
11			
12			
13			
14			
15	TOTAL Debits to Retained Earnings (Acct. 439)		
16	Balance Transferred from Income (Account 433 less Account 418.1)	216	78,552,574
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	4% Preferred (par value $100)	437	-564,076
25	Auction Rate Preferred, Series A (stated value $100,000)	437	-1,103,625
26	7.68% Serial Preferred (par value $100)	437	-1,152,000
27	7.07% Serial Preferred (par value $100,000)	437	-1,767,500
28			
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)		-4,587,201
30	Dividends Declared-Common Stock (Account 438)		
31	$2.50 Par Value		-70,177,884
32			
33			
34			
35			
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-70,177,884
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings	216	7,000,000
38	Balance - End of Year (Total 1,9,15,16,22,29,36,37)		316,065,712
	APPROPRIATED RETAINED EARNINGS (Account 215)		
39			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

STATEMENT OF RETAINED EARNINGS FOR THE YEAR

1. Report all changes in appropriated retained earnings, unappropriated retained earnings, and unappropriated undistributed subsidiary earnings for the year.
2. 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)
3. State the purpose and amount of each reservation or appropriation of retained earnings.
4. 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.
5. Show dividends for each class and series of capital stock.
6. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
7. 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.
8. 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)	Amount (c)
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
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		1,543,966
48	TOTAL Retained Earnings (Account 215, 215.1, 216) (Total 38, 47)		317,609,678
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account 216.1)		
49	Balance-Beginning of Year (Debit or Credit)		9,322,512
50	Equity in Earnings for Year (Credit) (Account 418.1)		10,368,122
51	(Less) Dividends Received (Debit)		7,000,000
52			
53	Balance-End of Year (Total lines 49 thru 52)		12,690,634

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

STATEMENT OF CASH FLOWS

1. If the notes to the cash flow statement in the respondents annual stockholders report are applicable to this statement, such notes should be included in page 122-123. Information about non-cash investing and financing activities should be provided on Page 122-123. Provide also on pages 122-123 a reconciliation between "Cash and Cash Equivalents at End of Year" with related amounts on the balance sheet.
2. Under "Other" specify significant amounts and group others.
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 on Page 122-123 the amount of interest paid (net of amounts capitalized) and income taxes paid.

Line No.	Description (See Instruction No. 5 for Explanation of Codes) (a)	Amounts (b)
1	Net Cash Flow from Operating Activities:	
2	Net Income	88,920,696
3	Noncash Charges (Credits) to Income:	
4	Depreciation and Depletion	85,334,384
5	Amortization of	11,541,352
6		
7		
8	Deferred Income Taxes (Net)	-81,357,140
9	Investment Tax Credit Adjustment (Net)	-456,311
10	Net (Increase) Decrease in Receivables	-4,643,397
11	Net (Increase) Decrease in Inventory	3,604,568
12	Net (Increase) Decrease in Allowances Inventory	
13	Net Increase (Decrease) in Payables and Accrued Expenses	75,738,603
14	Net (Increase) Decrease in Other Regulatory Assets	170,347,278
15	Net Increase (Decrease) in Other Regulatory Liabilities	1,023,878
16	(Less) Allowance for Other Funds Used During Construction	333,060
17	(Less) Undistributed Earnings from Subsidiary Companies	3,817,819
18	Other (provide details in footnote):	
19	Unbilled Revenues	1,686,536
20	Other Amort and Other - Net	17,106,484
21	Other than Temp Decline in Market Value of Investments	979,519
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	365,675,571
23		
24	Cash Flows from Investment Activities:	
25	Construction and Acquisition of Plant (including land):	
26	Gross Additions to Utility Plant (less nuclear fuel)	-125,277,281
27	Gross Additions to Nuclear Fuel	
28	Gross Additions to Common Utility Plant	
29	Gross Additions to Nonutility Plant	
30	(Less) Allowance for Other Funds Used During Construction	2,374,773
31	Other (provide details in footnote):	
32		
33		
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-127,652,054
35		
36	Acquisition of Other Noncurrent Assets (d)	
37	Proceeds from Disposal of Noncurrent Assets (d)	337,707
38		
39	Investments in and Advances to Assoc. and Subsidiary Companies	
40	Contributions and Advances from Assoc. and Subsidiary Companies	
41	Disposition of Investments in (and Advances to)	
42	Associated and Subsidiary Companies	
43		
44	Purchase of Investment Securities (a)	
45	Proceeds from Sales of Investment Securities (a)	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

STATEMENT OF CASH FLOWS

4. Investing Activities include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed on pages 122-123. Do not include on this statement the dollar amount of Leases capitalized per US of A General Instruction 20; instead provide a reconciliation of the dollar amount of Leases capitalized with the plant cost on pages 122-123.
5. Codes used:
(a) Net proceeds or payments.
(b) Bonds, debentures and other long-term debt.
(c) Include commercial paper.
(d) Identify separately such items as investments, fixed assets, intangibles, etc.
6. Enter on pages 122-123 clarifications and explanations.

Line No.	Description (See Instruction No. 5 for Explanation of Codes) (a)	Amounts (b)
46	Loans Made or Purchased	
47	Collections on Loans	
48		
49	Net (Increase) Decrease in Receivables	
50	Net (Increase) Decrease in Inventory	
51	Net (Increase) Decrease in Allowances Held for Speculation	
52	Net Increase (Decrease) in Payables and Accrued Expenses	
53	Other (provide details in footnote):	
54	Note Receivable Payment from Parent	11,859,184
55	Other Net	-2,269,862
56	Net Cash Provided by (Used in) Investing Activities	
57	Total of lines 34 thru 55)	-117,725,025
58		
59	Cash Flows from Financing Activities:	
60	Proceeds from Issuance of:	
61	Long-Term Debt (b)	200,000,000
62	Preferred Stock	
63	Common Stock	
64	Other (provide details in footnote):	
65		
66	Net Increase in Short-Term Debt (c)	
67	Other (provide details in footnote):	
68		
69		
70	Cash Provided by Outside Sources (Total 61 thru 69)	200,000,000
71		
72	Payments for Retirement of:	
73	Long-term Debt (b)	-77,000,000
74	Preferred Stock	-50,214,798
75	Common Stock	
76	Other (provide details in footnote): Other Net	-2,165,088
77	First Mortgage Bond Redemtion Cost	-2,094,000
78	Net Decrease in Short-Term Debt (c)	-272,051,387
79		
80	Dividends on Preferred Stock	-4,587,201
81	Dividends on Common Stock	-70,177,884
82	Net Cash Provided by (Used in) Financing Activities	
83	(Total of lines 70 thru 81)	-278,290,358
84		
85	Net Increase (Decrease) in Cash and Cash Equivalents	
86	(Total of lines 22,57 and 83)	-30,339,812
87		
88	Cash and Cash Equivalents at Beginning of Year	42,996,809
89		
90	Cash and Cash Equivalents at End of Year	12,656,997

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.

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

NOTES TO THE FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

Nature of Business

Idaho Power Company (IPC) is regulated by the Federal Energy Regulatory Commission (FERC) and the state regulatory commissions of Idaho and Oregon and is engaged in the generation, transmission, distribution, sale and purchase of electric energy. 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. Effective June 11,2001 IPC transferred its non-utility wholesale electricity marketing operations ("Energy Marketing") to IdaCorp Energy (IE). Energy Marketing net assets transferred consist primarily of energy trading contracts and trading accounts receivable and accounts payable.

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.

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.

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.

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 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 3.00 percent in 2002 and 2.98 percent in 2001.

Allowance for Funds Used During Construction

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 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 2002 and 2001 were 4.3 percent and 5.4 percent, respectively. IPC's reductions to interest expense for AFDC were $2 million and $4 million, and other income included $0.3 million and $1 million for 2002 and 2001, respectively.

Revenues

In order to match revenues with associated expenses, IPC accrues unbilled revenues for electric services delivered to customers but not yet billed at month-end.

Power Cost Adjustment

IPC has a Power Cost Adjustment (PCA) mechanism that provides for annual adjustments to the rates charged to its Idaho retail electric customers. These adjustments, which take effect annually in May, are based on forecasts of net power supply expenses 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 a true-up, is then included in the calculation of the next year's PCA adjustment.

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).

The State of Idaho allows a three-percent investment tax credit (ITC) upon certain qualifying plant additions. ITC's 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

At December 31, 2002, two stock-based employee compensation plans existed, which are described more fully in Note 8. These plans are 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 restricted stock are reflected in net income based on the market value at the award date, or the year-end price for shares not yet vested. No stock-based employee compensation cost is reflected in net income for stock options, as all options granted under these plans had an exercise price equal to the market value of the underlying common stock on the date of grant.

The following table illustrates the effect on net income if the fair value recognition provisions of SFAS 123, "Accounting for Stock-Based Compensation," had been applied to stock-based employee compensation:

	2002	2001
	(thousands of dollars)	
Net income, as reported	$ 88,920	$ 78,238
Add: Stock-based employee compensation expense included in reported net income, net of related tax effects	(10)	403
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	1,837	1,603
Pro forma net income	$ 87,073	$ 77,038

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.

SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION:

Cash paid (received) during the period for:	2002
Income taxes	$ (17,974)
Interest (net of amount capitalized)	56,167

Investments

Investments in marketable securities are accounted for in accordance with SFAS 115, "Accounting for Certain Investments in Debt and Equity Securities." These investments are classified as available-for-sale securities, and are reported at fair value, using either specific identification or average cost to determine the cost for computing gains or losses. Any unrealized gains or losses on available-for-sale securities are included in other comprehensive income. Additionally, these investments are evaluated to determine whether they have experienced a decline in market value that is considered other than temporary. Other than temporary declines in market value are included in other income.

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 various jurisdictions regulating IPC. The economic effects of regulation can result in regulated companies recording costs that have been or are expected to be allowed in the ratemaking process in a period different from the period in which the costs would be charged to expense by an unregulated enterprise. When this occurs, costs are deferred as regulatory assets in the balance sheet and recorded as expenses in the periods when those same amounts are reflected in rates. Additionally, regulators can impose liabilities upon a regulated company for amounts previously collected from customers and for amounts that are expected to be refunded to customers (regulatory liabilities).

Comprehensive Income

Comprehensive income includes net income, unrealized holding gains (losses) on marketable securities, IPC's proportionate share of unrealized holding gains (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.

Adopted Accounting Standards

In June 2001, the Derivative Implementation Group of the Financial Accounting Standards Board (FASB) issued Implementation Issue C-15, "Normal Purchases and Normal Sales Exception for Option-Type Contracts and Forward Contracts in Electricity," concluding that contracts subject to book-outs were not eligible for the normal purchase and sales exception in SFAS 133. Therefore, certain contracts were recorded as derivatives in prior periods. However, this Implementation Issue was revised in October 2001 and December 2001, and now allows these contracts to qualify for the exception. This revision applies only to electric utilities, due to the unique nature of the industry. IPC completed an evaluation of the effect of this revised Implementation Issue on its treatment of booked-out contracts and determined that contracts previously classified as derivatives were exempt. This change did not have a material effect on IPC's financial statements.

New Accounting Pronouncements

In June 2001, the FASB issued SFAS 143, "Accounting for Asset Retirement Obligations," which 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 and 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 expects to record regulatory assets and liabilities instead of accretion, depreciation and gains or losses, if the criteria for such treatment are met. SFAS 143 is effective beginning in 2003.

A detailed assessment of the applicability and implications of SFAS 143 has been performed. AROs related to IPC's three jointly owned coal-fired generation facilities, its transmission and distribution facilities and the Bridger Coal mine, which is owned by an equity-method investee, have been identified. When adopted in 2003, IPC expects to record ARO liabilities of $12 million and fixed assets of $6 million, with the offset to regulatory assets. These amounts do not include an amount for the transmission and distribution facilities, because, based on the indeterminate life of these assets, an ARO calculation cannot be made.

In June 2002, the FASB issued SFAS 146, "Accounting for Costs Associated with Exit or Disposal Activities." The standard requires companies to recognize costs associated with exit or disposal activities when they are incurred, rather than at the date of a commitment to an exit or disposal plan. Examples of costs covered by the standard include lease termination costs and certain employee severance costs that are associated with a restructuring, discontinued operation, plant closing or other exit or disposal activity. This standard supersedes EITF Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." SFAS 146 is to be applied prospectively to exit or disposal activities initiated after December 31, 2002. The adoption of SFAS 146 is not expected to have a material effect on IPC's financial statements.

In November 2002, the FASB issued Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." This Interpretation elaborates on the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under certain guarantees that it has issued. It also clarifies that a guarantor is required to recognize, at the inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. The initial recognition and measurement provisions of this Interpretation are applicable on a prospective basis to guarantees issued or modified after December 31, 2002, irrespective of the guarantor's fiscal year-end. The disclosure requirements in this Interpretation are effective for financial statements of interim or annual periods ending after December 15, 2002. The adoption of this Interpretation is not expected to have a material effect on IPC's financial statements.

In January 2003, the FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities." This Interpretation clarifies the application of Accounting Research Bulletin No. 51, "Consolidated Financial Statements," to certain entities in which equity investors do not have the characteristics of a controlling financial interest or in which equity investors do not bear the residual economic risks. The Interpretation applies to variable interest entities in which an enterprise obtains an interest after that date. It applies in the fiscal year or interim period beginning after June 15, 2003 to variable interest entities in which an enterprise holds a variable interest that was acquired before February 1, 2003. IPC has determined that it is not reasonably possible that they will be required to consolidate or disclose information about a variable interest entity upon the effective date of this Interpretation.

Common Stock

The outstanding shares of IPC's common stock were exchanged on a share-for-share basis into common stock of IDACORP, Inc. (IDACORP) on October 1, 1998 and are no longer actively traded. IPC's preferred stock and debt securities were unaffected.

Other Accounting Policies

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

2. INCOME TAXES:

IPC's effective tax rate for the year ended December 31, 2002 decreased from 38.9 percent in 2001 to a benefit of 4.9 percent in 2002. Tax benefit items occurring in 2002 include a tax accounting method change and the settlement of a partnership audit, which resulted in a decrease to tax expense.

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

	2002	2001
	(thousands of dollars)	
Computed income taxes based on statutory federal income tax rate	$ 29,660	$ 44,820
Change in taxes resulting from:		
Equity earnings of subsidiary companies	(3,629)	(2,413)
AFDC	(948)	(1,571)
Investment tax credits	(3,179)	(3,169)
Repair allowance	(2,450)	(2,800)
Removal cost	(815)	(329)
Capitalized overhead costs	(3,500)	-
Tax accounting method change	(31,162)	-
Settlement of prior years tax returns	-	-

State income taxes (net of federal reduction)	3,946	4,315
Depreciation	8,940	9,790
Other	(1,041)	1,177
Total (benefit) provision for income taxes	$ (4,178)	$ 49,820
Effective tax rate	(4.9)%	38.9%

The provision for income taxes consists of the following:

	2002	2001
	(thousands of dollars)	
Income taxes currently payable (receivable):		
Federal	$ 69,487	$ (42,381)
State	8,598	(12,544)
Total	78,085	(54,925)
Income taxes deferred:		
Federal	(76,352)	85,692
State	(5,455)	17,087
Total	(81,807)	102,779
Investment tax credits:		
Deferred	2,723	5,135
Restored	(3,179)	(3,169)
Total	(456)	1,966
Total (benefit) provision for income taxes	$ (4,178)	$ 49,820

The tax effects of significant items comprising IPC's net deferred tax liabilities are as follows:

	2002	2001
	(thousands of dollars)	
Deferred tax assets:		
Regulatory liabilities	$ 41,013	$ 41,290
Advances for construction	3,758	3,941
Other	19,802	(4,655)
Total	64,573	40,576
Deferred tax liabilities:		
Property, plant and equipment	230,935	250,180
Regulatory assets	327,934	209,832
Conservation programs	10,427	11,138
PCA	53,324	113,605
Other	30,346	9,288
Total	652,966	594,043
Net deferred tax liabilities	$ 588,393	$ 553,467

3. PREFERRED STOCK OF IDAHO POWER COMPANY:

The number of shares of IPC preferred stock outstanding at December 31, 2002 and 2001 were as follows:

	Shares Outstanding at December 31, 2002	Shares Outstanding at December 31, 2001	Call Price Per Share
Preferred stock:			
Cumulative, $100 par value:			
4% preferred stock (authorized 215,000 shares)	133,927	143,872	$104.00
Serial preferred stock, 7.68% Series (authorized 150,000 shares	150,000	150,000	$102.97
Serial preferred stock, cumulative, without par value, total of 3,000,000 shares authorized:			
7.07% Series, $100 stated value (authorized 250,000 shares) (a)	250,000	250,000	$100.354 - $103.535
Auction rate preferred stock, $100,000 stated value (authorized 500 shares)	-	500	
Total	533,927	544,372	

(a) The preferred stock is not redeemable prior to July 1, 2003.

IPC redeemed its auction rate preferred stock in August 2002 for $50 million using short-term borrowings.

During 2002 and 2001 IPC reacquired and retired 9,945 and 6,784 shares of 4% preferred stock. As of December 31, 2002, the overall effective cost of all outstanding preferred stock was 7.03 percent.

4. LONG-TERM DEBT:

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

	2002	2001
	(thousands of dollars)	
First mortgage bonds:		
6.85% Series due 2002	$ -	$ 27,000
6.40% Series due 2003	80,000	80,000
8 % Series due 2004	50,000	50,000
5.83% Series due 2005	60,000	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	-
Maturing 2023 through 2032 with rates ranging from 6.00% to 8.75%	180,000	130,000
Total first mortgage bonds	750,000	627,000
Pollution control revenue bonds:		
8.30% Series 1984 due 2014	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
REA notes	1,185	1,263
American Falls bond guarantee	19,885	19,885
Milner Dam note guarantee	11,700	11,700
Unamortized premium/discount - net	(2,405)	(1,029)
Total	950,825	829,279
Current maturities of long-term debt	(80,084)	(27,078)
Total long-term debt	$ 870,741	$ 802,201

At December 31, 2002, the maturities for the aggregate amount of long-term debt outstanding were (in thousands of dollars):

2003	$ 80,084
2004	50,077
2005	60,079
2006	82
2007	81,228
Thereafter	679,275
Total	$ 950,825

On March 23, 2000, IPC filed a $200 million shelf registration statement that could be used for first mortgage bonds (including medium-term notes), unsecured debt or preferred stock. On December 1, 2000, IPC issued $80 million of Secured Medium-Term Notes, Series C, 7.38% Series due 2007. Proceeds were used in January 2001 for the early redemption of $75 million First Mortgage Bonds 9.50% Series due 2021. On March 2, 2001, IPC issued $120 million of Secured Medium-Term Notes, Series C, 6.60% Series due 2011 with the proceeds used to reduce short-term borrowing incurred in support of ongoing long-term construction requirements. No amounts remain to be issued on this shelf registration statement.

On August 16, 2001, IPC filed a $200 million shelf registration statement that could be used for first mortgage bonds (including medium-term notes), unsecured debt or preferred stock. On November 15, 2002, IPC issued $200 million of secured medium-term notes. This issuance of medium-term notes was divided into two series. The first was $100 million First Mortgage Bonds 4.75% Series due 2012 and the second was $100 million First Mortgage Bonds 6.00% Series due 2032. Proceeds were used to pay down IPC short-term borrowings.

In August 2001, $25 million First Mortgage Bonds 9.52% Series due 2031 were redeemed early. Also, in March 2002, $50 million First Mortgage Bonds 8.75% Series due 2027 were redeemed early using short-term borrowings.

The amount of first mortgage bonds issuable by IPC is limited to a maximum of $900 million 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 indenture.

Pollution Control Revenue Bonds, Series 1984, due December 1, 2014, are secured by First Mortgage Bonds, Pollution Control Series A, which were issued by IPC and are held by a Trustee for the benefit of the bondholders.

On April 26, 2000, at the request of IPC, the American Falls Reservoir District issued its American Falls Refunding

Replacement Dam Bonds, Series 2000, in the aggregate principal amount of $20 million for the purpose of refunding on April 26, 2000 a like amount of its bonds dated May 1, 1990. IPC has guaranteed repayment of these bonds.

On May 17, 2000, tax exempt Pollution Control Revenue Refunding Bonds Series 2000, in the aggregate principal amount of $4 million, were issued by Port of Morrow, Oregon for the purpose of refunding on August 1, 2000, a like amount of its Pollution Control Revenue Bonds, Series 1978.

At December 31, 2002 and 2001, the overall effective cost of all outstanding first mortgage bonds and pollution control revenue bonds was 6.51 percent and 6.97 percent, respectively.

5. 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, fixed rate long-term debt and investments and other property are based upon quoted market prices of the same or similar issues or discounted cash flow analyses as appropriate.

	December 31, 2002		December 31, 2001	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	(thousands of dollars)			
Assets:				
Notes receivable	$ 9,646	$ 10,063	$ 12,009	$ 11,207
Investments and other property	20,401	20,401	16,729	16,729
Liabilities:				
Fixed rate long-term debt	953,230	1,015,612	830,508	867,808

6. NOTES PAYABLE:

At December 31, 2002, IPC had regulatory authority to incur up to $350 million of short-term indebtedness. IPC has a $200 million credit facility that expires March 25, 2003. Under this facility IPC pays a facility fee on the commitment, quarterly in arrears, based on IPC's corporate credit rating. IPC's commercial paper may be issued up to the amounts supported by the bank credit facilities.

Balances and interest rates of short-term borrowings were as follows at December 31 (in thousands of dollars):

	2002	2001
Balance	$ 10,500	$ 282,000
Effective interest rate	1.65%	2.10%

7. COMMITMENTS AND CONTINGENT LIABILITIES:

IPC is currently purchasing energy from 67 on-line cogeneration and small power production facilities with contracts ranging from one to 30 years. Under these contracts IPC is required to purchase all of the output from these facilities. During the year ended December 31, 2002, IPC purchased 692,414 MWh at a cost of $44 million.

IPC has agreed to guarantee the performance of reclamation activities at Bridger Coal Company of which Idaho Energy Resources Company, a subsidiary of IPC, owns a one-third interest. This guarantee, which is renewed each December, was $60 million at December 31, 2002.

From time to time IPC is a party to various other legal claims, actions and complaints not discussed below. IPC believes that they have meritorious defenses to all lawsuits and legal proceedings in which they are defendants and will vigorously defend against them although they are unable to predict with certainty whether or not they will ultimately be successful. However, based on our evaluation, management believes that the resolution of these matters will not have a material adverse effect on IPC's financial positions, 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 IDACORP Energy (IE). On March 9, 2001, Grays Harbor entered into a 20-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 alleges that the assignment was void and unenforceable, and seeks restitution from IE and IDACORP, or in the alternative, Grays Harbor alleges that the contract should be rescinded or reformed. Grays Harbor seeks 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 had this action removed from the state court to the United States 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 Federal District Court lacked jurisdiction as the matter is preempted under the FPA by the FERC. The court ruled in favor of the companies' motion to dismiss and dismissed the case with prejudice on January 28, 2003.

State of California Attorney General: The California Attorney General (AG) filed the complaint in this case in the California Superior Court in San Francisco on May 30, 2002. This is one of thirteen virtually identical cases brought by the AG against various sellers of power in the California market, seeking civil penalties pursuant to California's unfair competition law - California Business and Professions Code Section 17200. Section 17200 defines unfair competition as any "unlawful, unfair or fraudulent business act or practice . . . ." The AG alleges that IPC engaged in unlawful conduct by violating the Federal Power Act (FPA) in two respects: (1) by failing to file its rates with the FERC as required by the FPA; and (2) charging unjust and unreasonable rates in violation of the FPA. The AG alleges that there were "thousands of . . . sales or purchases" for which IPC failed to file its rates, and that IPC charged unjust and unreasonable rates on "thousands of occasions." Pursuant to Business and Professions Code Section 17206, the AG seeks civil penalties of up to $2,500 for each alleged violation. On June 25, 2002, IPC removed the action to federal court, and on July 25, 2002, the AG filed a motion to remand back to state court. The court previously denied the AG's prior motions to remand back to state court in the companion cases. The court heard IPC's Motion to Dismiss on September 26, 2002. The court has not yet ruled on the Motion to Dismiss. IPC intends to vigorously defend its position in this proceeding and believes this matter will not have a material adverse effect on its consolidated financial position, results of operations or cash flows.

Wholesale Electricity Antitrust Cases I & II: These cross-actions against IE and IPC emerge from multiple California state court proceedings first initiated in late 2000 against various power generators/marketers by various California municipalities and citizens, including California Lieutenant Governor Cruz Bustamante and California legislator Barbara Matthews in their personal capacities. 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., 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. Plaintiffs asserted various claims that the defendants violated California Antitrust Law (the Cartwright Act), Business & Professions Code Section 16720, *et seq*., and California's Unfair Competition Law, Business & Professions Code Section 17200, *et seq.* Among the acts complained of are bid rigging, information exchanges, withholding of power, and various other wrongful acts. These actions were subsequently consolidated, resulting in the filing of Plaintiffs' Master Complaint (PMC) in San Diego Superior Court on March 8, 2002.

On April 22, 2002, more than a year after the initial complaints had been 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 seek 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 PMC. Duke and Reliant also seek declaratory relief as to the respective liability and conduct of each of the cross-defendants in the actions alleged in the PMC. Reliant has also asserted a claim against IPC for alleged violations of the California Unfair Competition Law, Business and Professions Code Section 17200, *et seq.* As a buyer of electricity in California, Reliant seeks the same relief from the cross-defendants, including IPC, as that sought by plaintiffs in the PMC 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, have 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 Federal District Court granted Plaintiffs' Motion to Remand to State Court, and Defendants' Motion to Stay the Remand Order while they appeal the Order. As a result of the various motions, no trial date is set at this time. The companies cannot predict the outcome of this proceeding, nor can they evaluate the merits of any of the claims at this time but they intend to vigorously defend this lawsuit.

Idaho Rivers United: On December 10, 2002, Idaho Rivers United filed a complaint against IPC in U.S. District Court for the District of Idaho. The complaint alleges that IPC violated the Clean Water Act by discharging an amount of dredged and fill material into the navigable waters of the Snake River in excess of that allowed by a Section 404 permit issued by the U.S. Army Corps of Engineers. The action relates to work completed by IPC, pursuant to a Section 404 permit issued by the Corps on September 3, 1999, in the area of the tailrace downstream of IPC's Bliss hydroelectric project on the Snake River in Idaho. Idaho Rivers United asks the court to impose civil penalties on IPC under sections 309(d) and 505(a) of the Clean Water Act [33 U.S.C. Sections 1319(d) and 1365(a)], require IPC to pay for any remedial or restoration work necessary to amend any environmental harm caused by the alleged violation, and pay reasonable attorney fees. IPC received an extension of time in which to respond to the complaint and is having settlement discussions with Idaho Rivers United.

IPC cannot predict the outcome of this proceeding, nor can it evaluate the merits of any of the claims at this time but it intends to vigorously defend this lawsuit.

California Energy Situation: 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 exchange defaulted on a payment to the exchange, the other participants were required to pay their allocated share of the default amount to the exchange. 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 (SCE) payment default of $215 million for power purchases. IPC made this payment. On January 24, 2001, IPC terminated the participation agreement. On February 8, 2001, the CalPX sent a further invoice for $5 million, due February 20, 2001, as a result of alleged payment defaults by SCE, Pacific Gas and Electric Company (PG&E) 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 8th invoice. IPC essentially discontinued energy trading with 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 FERC to intervene in a proceeding that requested the FERC to suspend the use of the CalPX charge back methodology and provides for further oversight in the CalPX's implementation of its default mitigation procedures.

A preliminary injunction was granted by a Federal Judge in the Federal 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, PG&E filed for bankruptcy. The CalPX and Cal ISO were among the creditors of PG&E. To the extent that PG&E's bankruptcy filing affects the collectibility of the receivables from the CalPX and Cal ISO, the receivables from these entities are at greater risk.

The FERC issued an order on April 6, 2001 requiring the CalPX to rescind all chargeback actions related to PG&E's and SCE's liabilities. Shortly after that time, the CalPX segregated the CalPX chargeback amounts it had collected in a separate account. The CalPX claims it is awaiting further orders of the FERC and the bankruptcy court before distributing the funds that it collected under its chargeback tariff mechanism. Although certain parties to the California refund proceeding urged the FERC's Presiding Administrative Law Judge to consider the chargeback amounts in his determination of who owes what to whom, in his Certification of Proposed Findings on California Refund Liability, he concluded that the matter already was pending before the FERC for disposition.

Also 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 its 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. As to potential refunds, if any, IE believes its exposure is likely to be offset by amounts due from California entities. Multiple parties have filed requests for rehearing and petitions for review. The latter--more than 60--have been consolidated by the United States Court of Appeals for the Ninth Circuit and held in abeyance while the FERC continues its deliberations. The Ninth Circuit also directed the FERC to permit the parties to adduce additional evidence respecting market manipulation and although the California Parties (the California Attorney General, other state agencies and the California Investor Owned Utilities) have requested specific procedures to implement that requirement, the FERC has not yet acted on that request.

On November 20, 2002, the FERC issued an order allowing the parties to the California refund proceeding to conduct discovery for one hundred days into market manipulation by various sellers during the Western power crises of 2000 and 2001. At the conclusion of the discovery period parties alleging market manipulation are to submit their claims to the FERC and parties have until March 20, 2003 to submit evidence or comments in response, including assertions that cross-examination is warranted.

This case had been further complicated by an August 13, 2002 FERC staff (Staff) Report which included the recommendation to replace the published California indices for gas prices that the FERC previously established as just and reasonable for calculating a Mitigated Market Clearing Price (MMCP) to calculate refunds with other published indices for producing basin prices plus a transportation allowance. Staff's recommendation is grounded on speculation that some sellers had an incentive to report exaggerated prices to publishers of the indices, resulting in overstated published index prices. Staff bases its speculation in large part on a statistical correlation analysis of Henry Hub and California prices. If FERC accepts the Staff recommendation, the total amount of refunds could roughly double over earlier estimates. IE, in conjunction with others, submitted comments on the Staff recommendation - asserting that Staff's conclusions were incorrect in part on the basis of the fact that the Staff's correlation study ignored evidence of normal market forces and scarcity which created the pricing variations which Staff observed, rather than improper manipulation of reported prices. Beyond soliciting comments on the Staff recommendation, the FERC has not decided whether or how to proceed with consideration of a change in the gas pricing methodology which it previously approved.

Based upon that order and subject to possible modification based upon revision of the gas indices to be used, the Cal ISO would then be directed by the FERC to calculate revised refund amounts due from sellers of spot market power into the CalPX and Cal ISO during the refund period.

The Administrative Law Judge issued a Certification of Proposed Findings on California Refund Liability on December 12, 2002. The FERC has indicated the intention to largely conclude work on the California refund matters, including Judge Birchman's decision, the gas pricing component of its MMCP methodology and claims of market manipulation, before the end of the first quarter of 2003.

On March 3, 2003, a group of California parties, including the California Attorney General, the California Public Utilities Commission, the California Electricity Oversight Board, SCE and PG&E, filed materials with the FERC claiming that wholesale power suppliers manipulated the California market during 2000-2001. They seek approximately $8 billion in refunds for the state's ratepayers. A number of wholesale power suppliers were named in the filings, including IPC. IPC intends to vigorously defend in this matter, but they are unable to predict the outcome of this proceeding.

In addition, the July 25, 2001 FERC order established 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 (ALJ) submitted recommendations and findings to the FERC on September 24, 2001. The ALJ 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 ALJ's decision is a recommendation to the commissioners of the FERC. Multiple parties have submitted comments to the FERC respecting the ALJ's recommendations. The ALJ's recommended findings are pending at the FERC. The City of Tacoma and the Port of Seattle requested that the docket be reopened to allow the submission of additional evidence related to alleged manipulation of the power market by Enron and others. IE opposed that request. By order issued December 19, 2002, the FERC reopened the docket to allow interested parties to take additional discovery and present additional evidence related to alleged market manipulation and its intent on spot market sales in the Pacific Northwest. As is the case in the California refund proceeding, at the conclusion of the discovery period, parties alleging market manipulation are to submit their claims to the FERC and parties have until March 20, 2003 to submit evidence or comments in response, including assertions that cross-examination is warranted. Grays Harbor, whose civil litigation claims were dismissed, as noted above, has injected itself into the FERC proceedings asserting in discovery requests that its six month forward contract, for which performance has been completed, should be treated as a spot market contract for purposes of the FERC's consideration of refunds. Grays Harbor filed testimony on March 3, 2003 requesting refunds from IPC of $5 million. The company intends to defend vigorously.

In addition, the Port of Seattle, the City of Tacoma and Seattle City Light 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. These parties did not suggest any misconduct by IE or IPC. IE and IPC expect to defend against these generic claims, but are unable to predict the outcome of this matter.

IPC transferred its non-utility wholesale electricity marketing operations to IE in June 2001 effective June 1, 2001. Effective with this transfer, the outstanding receivables and payables with the CalPX and Cal ISO were assigned from IPC to IE. At December 31, 2002, the CalPX and Cal ISO owed IE $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 $42 million against these receivables.

Washington Retail Consumer Class Action Complaint: The complaint in this case was filed on December 20, 2002 in the United States District Court for the Western District of Washington at Seattle, against various entities, including IPC. The complaint was served on IPC on February 3, 2003. This action seeks class action status on behalf of all persons and businesses residing in Washington who were purchasers of electrical and/or natural gas energy from any period beginning in January 2000 to the present. The complaint alleges claims under the Washington Consumer Protection Act, RCW 19.86, as well as common law claims of fraud by concealment, negligence and for an accounting. The complaint asserts that the defendants, including IPC, engaged in, among other things, unfair and deceptive acts, in violation of the Federal Power Act, by (a) withholding the supply of energy; (b) misrepresenting the amount of its energy supplies; (c) exercising improper control over the energy markets; and (d) manipulating the price of energy markets resulting in energy rates being unjust, unreasonable and unlawful. The plaintiff seeks certification of a class action, equitable and injunctive relief, an accounting, treble damages, attorneys' fees and costs. On February 3, 2003, another defendant, Reliant, moved to transfer the case to the Judge who is presiding over MDL No. 1405. IPC's response to the complaint is due within 30 days from the date of service. IPC intends to vigorously defend against this lawsuit and believes this matter will not have a material adverse effect on its financial position, results of operations or cash flows.

Oregon Retail Consumer Class Action Complaint: The complaint in this case was filed on December 16, 2002 in the Circuit Court of the State of Oregon for the County of Multnomah, against various entities, including IPC. The complaint was served on IPC on February 7, 2003. The case was removed by another defendant, Reliant, to the United States District Court, District of Oregon on February 4, 2003. The complaint seeks class action status on behalf of all persons and businesses residing in Oregon who were purchasers of electrical and/or natural gas energy from any period beginning in January 2000 to the present. The complaint alleges claims under the Oregon Unfair Trade Practices Act, ORS 646.605 *et seq.* in addition to claims of fraud by concealment, negligence and for an accounting. The complaint asserts that the defendants, including IPC, engaged in, among other things, unfair and deceptive acts, in violation of the Federal Power Act, by (a) withholding the supply of energy; (b) misrepresenting the amount of its energy supplies; (c) exercising improper control over the energy markets; and (d) manipulating the price of energy markets resulting in energy rates being charged to Oregon energy consumers that were unjust, unreasonable and unlawful. The plaintiff seeks certification of a class action, equitable and injunctive relief, an accounting, attorneys' fees and costs. The action was recently removed to federal court, and IPC intends to seek an extension of time to respond. IPC intends to vigorously defend against this lawsuit and believes this matter will not have a material adverse effect on its financial position, results of operations or cash flows.

8. STOCK-BASED COMPENSATION:

IPC participates in two stock-based compensation plans of IDACORP that are intended to align employee and shareholders objectives related to the long-term growth of IPC.

IDACORP adopted the 2000 Long Term Incentive and Compensation Plan (LTICP) for officers, key employees and directors including those of IPC. The LTICP 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.

Stock option transactions are summarized as follows:

	2002		2001	
	Number of shares	Weighted average exercise price	Number of shares	Weighted average exercise price
Outstanding beginning of year	477,000	$ 37.79	220,000	$ 35.81
Granted	244,950	39.50	257,000	39.48
Exercised	-	-	-	-
Cancelled	-	-	-	-
Outstanding end of year	721,950	$ 38.37	477,000	$ 37.79
Exercisable	139,400	$ 37.16	44,000	$ 35.81

The outstanding options have a range of exercise prices from $35.81 to $40.31. As of December 31, 2002, the weighted average remaining contractual life is 8.3 years.

IDACORP also has a restricted stock plan for certain key employees including those of IPC. Each grant made under this plan has a three-year restricted period, and the final award amounts depend on the attainment of cumulative EPS performance goals. At December 31, 2002 there were 201,539 IDACORP shares remaining available under this plan.

Restricted stock awards are compensatory awards and IPC accrues compensation expense (which is charged to operations) based upon the market value of the granted shares. For the years 2002 and 2001, total compensation accrued under the plan was less than $1 million annually.

The following table summarizes restricted stock activity for the years 2002 and 2001:

	2002	2001
Shares outstanding - beginning of year	53,878	52,719
Shares granted	37,197	20,311
Shares forfeited	(179)	(474)
Shares issued	(18,767)	(18,678)
Shares outstanding - end of year	72,129	53,878
Weighted average fair value of current year stock grants on grant date	$ 38.64	$ 38.02

9. 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 but not more than the maximum amount deductible for income tax purposes. IPC was not required to contribute to the plan in 2002 and 2001. The trustee invests the plan assets primarily in listed stocks (both U.S. and foreign), fixed income securities and investment grade real estate.

IPC has a nonqualified, deferred compensation plan for certain senior management employees and directors. This plan was financed by purchasing life insurance policies and investments in marketable securities, all of which are held by a trustee. The cash value of the policies and investments exceed the projected benefit obligation of the plan but do not qualify as plan assets in the actuarial computation of the funded status.

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

	Pension Plan		Deferred Compensation Plan	
	2002	2001	2002	2001
	(in thousands of dollars)			
Service cost	$ 9,548	$ 7,978	$ 944	$ 624
Interest cost	18,684	17,634	2,108	2,039
Expected return on assets	(28,797)	(30,117)	-	-

Recognized net actuarial (gain) loss	-	(3,179)	498	281
Amortization of prior service cost	729	708	(353)	(345)
Amortization of transition asset	(263)	(263)	613	613
Net periodic pension (benefit) cost	$ (99)	$ (7,239)	$ 3,810	$ 3,212

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

	Pension Plan		**Deferred Compensation Plan**	
	2002	**2001**	**2002**	**2001**
	(in thousands of dollars)			
Change in projected benefit obligation:				
Benefit obligation at January 1	$ 273,208	$ 241,281	$ 30,405	$ 27,876
Service cost	9,548	7,978	944	624
Interest cost	18,684	17,634	2,108	2,039
Actuarial loss (gain)	6,823	18,560	4,490	2,352
Benefits paid	(13,382)	(12,586)	(2,507)	(2,420)
Plan amendments	-	341	352	(66)
Benefit obligation at December 31	294,881	273,208	35,792	30,405
Change in plan assets:				
Fair value at January 1	326,266	340,789	-	-
Actual return on plan assets	(30,353)	(1,936)	-	-
Employer contributions	-	-	-	-
Benefit payments	(13,382)	(12,586)	-	-
Fair value at December 31	282,531	326,267	-	-
Funded status	(12,350)	53,059	(35,792)	(30,405)
Unrecognized actuarial loss (gain)	34,116	(31,857)	12,505	8,513
Unrecognized prior service cost	6,860	7,589	630	(75)
Unrecognized net transition liability	(652)	(916)	1,536	2,149
Net amount recognized	$ 27,974	$ 27,875	$ (21,121)	$ (19,818)
Amounts recognized in the statement of financial position consist of:				
Prepaid (accrued) pension cost	$ 27,974	$ 27,875	$ (33,120)	$ (28,500)
Intangible asset	-	-	2,166	2,074
Accumulated other comprehensive income	-	-	9,833	6,608
Net amount recognized	$ 27,974	$ 27,875	$ (21,121)	$ (19,818)

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

	Pension Benefits		**Postretirement Benefits**	
	2002	**2001**	**2002**	**2001**
Discount rate	6.75%	7.0%	6.75%	7.0%
Expected long-term rate of return on assets	8.5	9.0	8.5	9.0
Annual salary increases	4.5	4.5	-	-

Employee Savings Plan

IPC has an Employee Savings Plan which 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 each of 2002 and 2001.

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, their spouses and qualifying dependents.

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

	2002	2001
Service cost	$ 927	$ 831
Interest cost	3,648	3,589
Expected return on plan assets	(2,320)	(2,343)
Amortization of unrecognized transition obligation	2,040	2,040
Amortization of prior service cost	(563)	(563)
Recognized actuarial (gain)/loss	487	-
Net periodic post-retirement benefit cost	$ 4,219	$ 3,554

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

	2002	2001
Change in accumulated benefit obligation:		
Benefit obligation at January 1	$ 53,650	$ 48,806
Service cost	927	831
Interest cost	3,648	3,589
Plan amendments	-	600
Actuarial loss	2,029	3,296
Benefits paid	(2,987)	(3,472)
Benefit obligation at December 31	57,267	53,650
Change in plan assets:		
Fair value of plan assets at January 1	25,184	26,071
Actual (loss) return on plan assets	(3,837)	(2,004)
Employer contributions	4,262	4,413
Benefits paid	(3,087)	(3,296)
Fair value of plan assets at December 31	22,522	25,184
Funded status	(34,745)	(28,466)
Unrecognized prior service cost	(5,610)	(6,173)
Unrecognized actuarial loss (gain)	18,627	10,828
Unrecognized transition obligation	20,400	22,440
Accrued benefit obligations included with other deferred credits	$ (1,328)	$ (1,371)

The assumed health care cost trend rate used to measure the expected cost of benefits covered by the plan is 6.75%. 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	1-Percentage-Point decrease
Effect on total of service and interest cost components	$ 261	$ (204)
Effect on accumulated postretirement benefit obligation	$ 2,477	$ (2,008)

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 is being amortized over ten years.

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

	2002	2001
Included with regulatory assets	$ 698	$ 1,032
Included with other deferred credits	$ (2,941)	$ (3,010)

10. UTILITY PLANT IN SERVICE 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 2002 and 2001 (in thousands of dollars):

	2002		2001	
	Balance	Avg Rate	Balance	Avg Rate
Production	$ 1,433,627	2.63%	$ 1,424,777	2.58%
Transmission	485,349	2.30	460,149	2.30
Distribution	902,985	3.31	854,445	3.34
General and Other	265,004	6.16	250,259	6.12
Total in service	3,086,965	3.00%	2,989,630	2.98%
Accumulated provision for depreciation	(1,294,961)		(1,220,002)	
In service - net	$ 1,792,004		$ 1,769,628	

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 Statements of Income. These facilities, and the extent of IPC's participation, are as follows at December 31, 2002:

		Company Ownership				
Name of Plant	**Location**	**Utility Plant In Service**	**Construction Work in Progress**	**Accumulated Provision for Depreciation**	**%**	**MW**
		(thousands of dollars)				
Jim Bridger Units 1-4	Rock Springs, WY	$ 410,694	$ 306	$ 233,367	33	707
Boardman	Boardman, OR	64,613	4,865	40,274	10	55
Valmy Units 1 and 2	Winnemucca, NV	303,157	3,283	164,995	50	261

IPC's wholly owned subsidiary, Idaho Energy Resources Company, is a joint venturer in Bridger Coal Company, which operates the mine supplying coal for the Jim Bridger steam generation plant. Coal purchased by IPC from the joint venture amounted to $44 million in 2002 and $43 million in 2001.

IPC has contracts to purchase the energy from four Public Utilities Regulatory Policy Act Qualified Facilities that are 50 percent owned by Ida-West. Power purchased from these facilities amounted to $7 million in 2002 and $6 million in 2001.

11. REGULATORY MATTERS:

Wind Down of Energy Marketing

IDACORP announced on June 21, 2002 that IE would wind down its power marketing operations. In connection with the wind down, certain matters were identified that require resolution with the FERC or the IPUC. Matters that need to be resolved with the FERC include:

- A utility such as IPC is entitled to transmission priority for its retail customers, while transmission for trading transactions must be purchased under the utility's open access tariff on the same basis as third parties. It appears that in some transactions this distinction was not observed;
- Certain transactions between a utility and an affiliate are required to have prior FERC approval. Such prior approval was not sought for some electricity transactions between IE and IPC, such as spinning reserves and load following services, which are common industry services; and
- Although IPC informed the FERC before IE was split off from IPC that it intended to move the utility's power marketing business to IE, IPC's power marketing contracts were assigned without formally obtaining the requisite prior approval of the FERC.

IE and IPC voluntarily contacted the FERC in September 2002 to discuss these matters. Since September, the FERC has made several requests for certain documents and other information all of which, except for those requests which have been deferred, IE and IPC have supplied. IE and IPC made additional filings with the FERC in November 2002, which included requests for approval of certain electricity transactions, the assignment of certain contracts between IPC and IE and termination of the Electricity Supply Management Services Agreement entered into between IPC and IE in June 2001.

On February 26, 2003, the FERC approved the assignment of certain wholesale power and transmission services agreements from IPC to IE. The FERC also found that IPC violated Section 203 of the Federal Power Act (FPA) by assigning the agreements in June 2001 without seeking prior approval from the FERC. The FERC noted that noncompliance with Section 203 of the FPA may prompt the FERC in certain instances to impose remedies as a condition of its approval; however, no such remedies were imposed in the FERC order.

Should the FERC conclude that its regulations or rate schedules were not complied with, it has significant discretion as to the appropriate remedies, if any. The FERC's remedial authority includes the authority to require refunds, to order equitable relief, to suspend the authorization to sell wholesale power at market-based rates, and, in some instances, to impose monetary penalties.

In an IPUC proceeding that has been underway since May 2001, IPC and the IPUC staff have been working to determine the appropriate compensation IE should provide to IPC as a result of transactions between the affiliates. Similar state regulatory issues relating to the period prior to February 2001 were determined by the IPUC in Order No. 28852 issued on September 28, 2001. The IPUC ruled on these transactions again in Order No. 29026 for the time period from March 2001 through March 2002. The IPUC also approved IPC's ongoing hedging and risk management strategies in Order No. 29102 issued August 28, 2002. This formalized IPC's agreement to implement a number of changes to its existing practices for managing risk and initiating hedging purchases and sales. In the same order, the IPUC directed IPC to present a resolution or a status report to the IPUC no later than December 20, 2002 on additional compensation due to the utility for the use of its transmission system and other capital assets by IE and any remaining transfer pricing issues. On December 20, 2002, a status report was filed with the IPUC reporting no significant developments. IPC committed to providing another status report to the IPUC on March 20, 2003.

IDACORP does not believe that resolution of these transactions will have any adverse impact on its ongoing operations. However, because it cannot be predicted at this point what regulatory actions might be taken or when, it cannot be determined what effect there may be on earnings and whether it will be material.

As previously disclosed, the FERC filing made on May 14, 2001, with respect to the pricing of real-time energy transactions between IPC and IE, is still under review by the FERC. For the period June 2001 through March 2002, IE paid IPC approximately $6 million, which was calculated based upon the pricing methodology for the period that was most favorable to IPC. This amount was credited to Idaho retail customers through the PCA. An additional $1 million has been paid to IPC for the period April 2002 through July 2002 based upon the same pricing methodology. However, until the FERC takes final action on this filing, rates for real-time transactions between IE and IPC are subject to adjustment.

However on April 15, 2003 annual PCA filing with the IPUC, IPC included some additional compensation related to one of the issues, in anticipation of settlement with the FERC. As a result of the anticipated FERC settlement, IE paid IPC an additional $2 million for spinning reserves and load following services. IPC proposed that the additional compensation be flowed through the 2003-2004 PCA. Other state regulatory issues are expected to be addressed following the conclusion of the FERC review.

Deferred Power Supply Costs

IPC's deferred power supply costs consist of the following at December 31, 2002 and 2001 (in thousands of dollars):

	2002	2001
Oregon deferral	$ 14,172	$ 14,866
Idaho PCA current year power supply cost deferrals:		
Deferral for 2001-2002 rate year	-	78,395
Deferral for 2002-2003 rate year	8,910	-
Irrigation load reduction program	-	69,586
Astaris load reduction agreement	27,160	62,247

Idaho PCA true-up awaiting recovery:		
Irrigation and small general service deferral for recovery in the 2003-2004 rate year	12,049	-
Industrial customer deferral for recovery in the 2003-2004 rate year	3,744	-
Remaining true-up authorized October 2001	-	36,500
Remaining true-up authorized May 2001	-	42,895
Remaining true-up authorized May 2002	74,253	-
Total deferral	$ 140,288	$ 304,489

Idaho: IPC has a PCA mechanism that provides for annual adjustments to the rates charged to its Idaho retail customers. These adjustments, which take effect in May, are based on forecasts of net power supply expenses 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 a true-up, is then included in the calculation of the next year's PCA adjustment.

So far in the 2002-2003 PCA rate year actual power supply costs have exceeded those anticipated in the forecast. Below normal water conditions are still impacting power supply costs even though power supply prices are significantly lower. In addition an Irrigation Load Reduction Program was completed in the 2001-2002 PCA rate year and the Astaris Voluntary Load Reduction costs have decreased, both reducing the PCA regulatory account balance from $290 million as of December 31, 2001 to $126 million as of December 31, 2002.

On May 13, 2002, the IPUC issued Order No. 29026 related to the 2002-2003 PCA rate filing. The order granted recovery of $255 million of excess power supply costs, consisting of:

- $209 million of voluntary load reduction and power supply costs incurred between March 1, 2001 and March 31, 2002.
- $28 million of excess power supply costs forecasted for the period April 2002 through March 2003.
- $18 million of unamortized costs previously approved for recovery beginning October 1, 2001. The amount authorized in October 2001 totaled $49 million. This order spreads the remaining October 2001 rate increase, which would have ended in September 2002, through May 2003.

The order also:

- Denied recovery of $12 million of lost revenues resulting from the Irrigation Load Reduction Program, and $2 million of other costs IPC sought to recover.
- Deferred recovery of $12 million of costs related to irrigation and small general service customers. In June 2002, the IPUC issued Order No. 29065 deferring an additional $4 million applicable to certain industrial customers. The $16 million will be recovered during the 2003-2004 PCA rate year, and IPC will earn a six percent carrying charge on the balance.
- Denied IPC's request to issue $172 million in Energy Cost Recovery Bonds, which would have spread the recovery of that amount over three years.
- Discontinued the IPUC-required three-tiered rate structure for residential customers.
- Authorized a separate surcharge to collect approximately $3 million annually to fund future conservation programs.

The IPUC had previously issued Order No. 28992 on April 15, 2002 disallowing the lost revenue portion of the Irrigation

Load Reduction Program. IPC believes that the IPUC's order is 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 still believes it should be entitled to receive recovery of this amount and has asked the Idaho Supreme Court to review the IPUC's decision. If successful, IPC would record any amount recovered as revenue.

In the May 2001 PCA filing, IPC requested recovery of $227 million of power supply costs. The IPUC subsequently issued Order No. 28772 authorizing recovery of $168 million, but deferring recovery of $59 million pending further review. The approved amount resulted in an average rate increase of 31.6 percent. After conducting hearings on the remaining $59 million, the IPUC in Order No. 28552 authorized recovery of $48 million plus $1 million of accrued interest, beginning in October 2001. The remaining $11 million not recovered in rates from the PCA filing was written off in September 2001.

In October 2001, IPC filed an application with the IPUC for an order approving inclusion in the 2002-2003 PCA of costs incurred for the Irrigation Load Reduction Program and the FMC/Astaris Load Reduction Agreement. These two programs were implemented in 2001 to reduce demand and were approved by the IPUC and the OPUC. The costs incurred in 2001 for these two programs were $70 million for the Irrigation Load Reduction Program and $62 million for the FMC/Astaris Load Reduction Agreement. The IPUC subsequently issued Order No. 28992 authorizing IPC to include direct costs it has accrued in the programs, subject to later adjustments in the 2002-2003 PCA year. As mentioned earlier, the IPUC also denied IPC's request to recover lost revenues experienced from the Irrigation Load Reduction Program.

The May 2000 PCA rate adjustment increased Idaho general business customer rates by 9.5 percent, and resulted from forecasted below-average hydroelectric generating conditions. Overall, the PCA adjustment increased general business revenue by approximately $38 million during the 2000-2001 rate period.

Oregon: IPC has also filed applications with the OPUC to recover calendar year 2001 extraordinary power supply costs applicable to the Oregon jurisdiction. In two separate 2001 orders, the OPUC has approved rate increases totaling six percent, which is the maximum annual rate of recovery allowed under Oregon state law. These increases are recovering approximately $2 million annually. The Oregon deferred balance is $14 million as of December 31, 2002.

Regulatory Assets and Liabilities

The following is a breakdown of IPC's regulatory assets and liabilities for the years 2002 and 2001:

	2002		2001	
	Assets	Liabilities	Assets	Liabilities
	(thousands of dollars)			
Income taxes	$ 327,934	$ 41,013	$ 209,832	$ 41,290
Conservation	24,450	4,402	28,324	3,524
Employee benefits	1,909	-	2,825	-
PCA deferral and amortization	126,116	-	289,623	-
Oregon deferral and amortization	14,172	-	14,866	-
Derivatives	91	-	47,781	-
Other	4,634	1,272	5,991	1,126
Deferred investment tax credits	-	67,560	-	68,016
Total	$ 499,306	$ 114,247	$ 599,242	$ 113,956

At December 31, 2002, IPC had $3 million of regulatory assets, primarily SFAS 112, "Employers Accounting for Postemployment Benefits" benefits and reorganization costs, that were not earning a return on investment (excluding the $328 million that relates to income taxes). The amortization period is three to four years.
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.

12. RELATED PARTY TRANSACTIONS:

In exchange for the transfer of Energy Marketing to IE in June 2001, IPC received a partnership interest in IE, which was then transferred to IDACORP in exchange for notes receivable from IDACORP totaling approximately $76 million. This amount represents the historical book value of the transferred Energy Marketing net assets on May 31, 2001 of $21 million and retained intercompany tax liabilities of $55 million. The notes receivable are due over periods of one to ten years and bear interest at IDACORP's overall variable short-term borrowing rate, which was 1.8 percent at December 31, 2002. The balance of this note at December 31, 2002 is approximately $22 million, including accrued interest.

In September 2002, IPC borrowed $100 million from IDACORP in order to repay a like amount of floating rate notes. This amount was repaid, with interest, on November 15, 2002.

In 2002 and 2001, IPC paid IE approximately $2 million annually under the Electricity Supply Management Services Agreement. IPC and IE requested termination of this agreement in a November 2002 FERC filing.

The following table presents IPC's sales to and purchases from IE for the years ended December 31:

	2002	2001
	(thousands of dollars)	
Sales to IE	$ 27,182	$ 21,288
Purchases from IE	13,665	34,843

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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

Line No.	Classification (a)	Total (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	3,087,419,093	3,087,419,093
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	3,087,419,093	3,087,419,093
9	Leased to Others		
10	Held for Future Use	2,335,078	2,335,078
11	Construction Work in Progress	92,481,654	92,481,654
12	Acquisition Adjustments	-454,449	-454,449
13	Total Utility Plant (8 thru 12)	3,181,781,376	3,181,781,376
14	Accum Prov for Depr, Amort, & Depl	1,294,961,078	1,294,961,078
15	Net Utility Plant (13 less 14)	1,886,820,298	1,886,820,298
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	1,269,613,653	1,269,613,653
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	25,584,115	25,584,115
22	Total In Service (18 thru 21)	1,295,197,768	1,295,197,768
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	-236,690	-236,690
33	Total Accum Prov (equals 14) (22,26,30,31,32)	1,294,961,078	1,294,961,078

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication		
3	Nuclear Materials		
4	Allowance for Funds Used during Construction		
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)		
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)		
9	In Reactor (120.3)		
10	SUBTOTAL (Total 8 & 9)		
11	Spent Nuclear Fuel (120.4)		
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)		
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)		
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
			2
			3
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			22

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/2003	Year of Report Dec. 31, 2002

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

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. 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 which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d) reversals of tentative distributions of prior year of unclassified retirements. Show in a footnote 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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	5,703	9,093
3	(302) Franchises and Consents	7,986,088	-776,660
4	(303) Miscellaneous Intangible Plant	52,886,199	7,273,666
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	60,877,990	6,506,099
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,275,203	
9	(311) Structures and Improvements	128,777,026	331,640
10	(312) Boiler Plant Equipment	443,607,191	6,016,413
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	109,330,890	1,050,126
13	(315) Accessory Electric Equipment	61,467,797	132,208
14	(316) Misc. Power Plant Equipment	12,574,083	191,055
15	TOTAL Steam Production Plant (Enter Total of lines 8 thru 14)	757,032,190	7,721,442
16	B. Nuclear Production Plant		
17	(320) Land and Land Rights		
18	(321) Structures and Improvements		
19	(322) Reactor Plant Equipment		
20	(323) Turbogenerator Units		
21	(324) Accessory Electric Equipment		
22	(325) Misc. Power Plant Equipment		
23	TOTAL Nuclear Production Plant (Enter Total of lines 17 thru 22)		
24	C. Hydraulic Production Plant		
25	(330) Land and Land Rights	13,935,724	
26	(331) Structures and Improvements	126,853,319	372,006
27	(332) Reservoirs, Dams, and Waterways	242,582,952	108,594
28	(333) Water Wheels, Turbines, and Generators	181,422,886	720,648
29	(334) Accessory Electric Equipment	34,495,211	993,630
30	(335) Misc. Power PLant Equipment	13,588,183	270,177
31	(336) Roads, Railroads, and Bridges	6,933,691	
32	TOTAL Hydraulic Production Plant (Enter Total of lines 25 thru 31)	619,811,966	2,465,055
33	D. Other Production Plant		
34	(340) Land and Land Rights	213,791	4,976
35	(341) Structures and Improvements	852,850	353,512
36	(342) Fuel Holders, Products, and Accessories	1,637,976	36,701
37	(343) Prime Movers	747,458	17,399
38	(344) Generators	40,868,666	2,013,950
39	(345) Accessory Electric Equipment	1,193,280	53,872

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
40	(346) Misc. Power Plant Equipment	2,419,087	70,337
41	TOTAL Other Prod. Plant (Enter Total of lines 34 thru 40)	47,933,108	2,550,747
42	TOTAL Prod. Plant (Enter Total of lines 15, 23, 32, and 41)	1,424,777,264	12,737,244
43	3. TRANSMISSION PLANT		
44	(350) Land and Land Rights	13,887,850	2,856,954
45	(352) Structures and Improvements	29,065,022	-1,298,280
46	(353) Station Equipment	184,645,277	19,614,480
47	(354) Towers and Fixtures	55,140,863	2,026,652
48	(355) Poles and Fixtures	80,179,114	1,218,127
49	(356) Overhead Conductors and Devices	96,912,093	5,399,938
50	(357) Underground Conduit		
51	(358) Underground Conductors and Devices		
52	(359) Roads and Trails	318,352	
53	TOTAL Transmission Plant (Enter Total of lines 44 thru 52)	460,148,571	29,817,871
54	4. DISTRIBUTION PLANT		
55	(360) Land and Land Rights	3,437,394	-488,109
56	(361) Structures and Improvements	13,306,974	1,639,108
57	(362) Station Equipment	102,170,691	18,604,866
58	(363) Storage Battery Equipment		
59	(364) Poles, Towers, and Fixtures	166,092,613	7,758,051
60	(365) Overhead Conductors and Devices	86,633,411	4,296,184
61	(366) Underground Conduit	28,582,949	3,105,331
62	(367) Underground Conductors and Devices	119,073,667	7,264,137
63	(368) Line Transformers	248,883,111	7,601,197
64	(369) Services	42,622,542	2,364,052
65	(370) Meters	37,736,793	2,261,146
66	(371) Installations on Customer Premises	2,086,143	167,608
67	(372) Leased Property on Customer Premises		
68	(373) Street Lighting and Signal Systems	3,818,844	147,122
69	TOTAL Distribution Plant (Enter Total of lines 55 thru 68)	854,445,132	54,720,693
70	5. GENERAL PLANT		
71	(389) Land and Land Rights	8,750,596	155,334
72	(390) Structures and Improvements	56,337,128	2,497,684
73	(391) Office Furniture and Equipment	48,986,891	5,889,073
74	(392) Transportation Equipment	37,257,775	6,018,873
75	(393) Stores Equipment	881,755	130,215
76	(394) Tools, Shop and Garage Equipment	3,415,716	244,010
77	(395) Laboratory Equipment	8,699,229	252,000
78	(396) Power Operated Equipment	6,270,802	150,444
79	(397) Communication Equipment	17,370,676	2,488,210
80	(398) Miscellaneous Equipment	1,864,816	148,177
81	SUBTOTAL (Enter Total of lines 71 thru 80)	189,835,384	17,974,020
82	(399) Other Tangible Property		
83	TOTAL General Plant (Enter Total of lines 81 and 82)	189,835,384	17,974,020
84	TOTAL (Accounts 101 and 106)	2,990,084,341	121,755,927
85	(102) Electric Plant Purchased (See Instr. 8)		
86	(Less) (102) Electric Plant Sold (See Instr. 8)		
87	(103) Experimental Plant Unclassified		
88	TOTAL Electric Plant in Service (Enter Total of lines 84 thru 87)	2,990,084,341	121,755,927

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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

instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

6. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, 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.

7. 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.

8. 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 of such filing.

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			14,796		2
		-22,375	7,187,053		3
232,747			59,927,118		4
232,747		-22,375	67,128,967		5
					6
					7
			1,275,203		8
33,069			129,075,597		9
1,768,650			447,854,954		10
					11
338,777			110,042,239		12
572,655			61,027,350		13
1,013,765			11,751,373		14
3,726,916			761,026,716		15
					16
					17
					18
					19
					20
					21
					22
					23
					24
			13,935,724		25
59,996			127,165,329		26
1,005			242,690,541		27
			182,143,534		28
79,091			35,409,750		29
10,642			13,847,718		30
			6,933,691		31
150,734			622,126,287		32
					33
			218,767		34
			1,206,362		35
			1,674,677		36
			764,857		37
			42,882,616		38
10,046			1,237,106		39

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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.
			2,489,424		40
10,046			50,473,809		41
3,887,696			1,433,626,812		42
					43
363			16,744,441		44
117,319		-3,371	27,646,052		45
3,683,451		35,895	200,612,201		46
			57,167,515		47
208,940			81,188,301		48
639,468			101,672,563		49
					50
					51
			318,352		52
4,649,541		32,524	485,349,425		53
					54
45		26,440	2,975,680		55
56,378		-26,440	14,863,264		56
893,712		-77,144	119,804,701		57
					58
1,036,102			172,814,562		59
687,163			90,242,432		60
82,208			31,606,072		61
674,025			125,663,779		62
1,207,899			255,276,409		63
189,994			44,796,600		64
1,157,698			38,840,241		65
38,964			2,214,787		66
					67
80,005			3,885,961		68
6,104,193		-77,144	902,984,488		69
					70
346,000			8,559,930		71
1,956,625		3,371	56,881,558		72
4,721,419		38,230	50,192,775		73
1,695,448			41,581,200		74
			1,011,970		75
131,888		1,288	3,529,126		76
222,869		4,918	8,733,278		77
26,685			6,394,561		78
413,559			19,445,327		79
32,505		19,188	1,999,676		80
9,546,998		66,995	198,329,401		81
					82
9,546,998		66,995	198,329,401		83
24,421,175			3,087,419,093		84
					85
					86
					87
24,421,175			3,087,419,093		88

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/2003	Year of Report Dec. 31, 2002

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
2					
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46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Boise Operations Center	12/31/82		768,377
3				
4	Production			152,419
5				
6	Transmission Stations			509,893
7				
8	Transmission Lines			86,981
9				
10	Distribution Stations			409,412
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21	Other Property:			
22	Boise Operations Center	12/31/82		72,785
23	Boise Mechanical and Electrical Shop	12/31/01		47,000
24	Transmission Stations	12/31/81		178,094
25	Distribution Stations			110,117
26				
27				
28				
29				
30				
31	Column B if no date listed it is various			
32				
33	Column C is unknown			
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			2,335,078

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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	RELIC COST BROWNLEE	19,534,582
2	RELIC COST HELLS CANYON	13,527,111
3	RELIC COST OXBOW	6,046,519
4	BROWNLEE-OXBOW 230KV UPGRADE	1,543,373
5	RELIC COST LOW MALAD	1,403,418
6	LINE 710, LCST-CDWL 230 KV	1,392,752
7	BRIDGER UNDISTRIBUTED WORK ORDER	1,337,243
8	ROLLUP RELIC COST UP MALAD	883,937
9	BRIDGER 2000C064 FGD POND GEOTHERMAL	802,432
10	KUNA-KUNA JUNCTION 138KV TRANS	787,201
11	BRIDGER 2002C011 U3 CONTROLS	767,158
12	VALMY UNDISTRIBUTED WORK ORDER	695,186
13	VALMY 24046 U1 BAG REPLACEMENT	626,865
14	WYEE-CONVERT SUBSTATION TO 138	617,569
15	CAPITAL SECURITY COSTS HELLS	611,730
16	BMRS0101-INSTALL DIGITAL MW	558,545
17	IPCO*INSTALL BOULDER TAP	505,799
18	HELLS CANYON RELICENSING	456,398
19	BOBN - UPGRADE SO11 & SO12 CON	445,995
20	BRIDGER 2002C012 SO3 FLUE GAS	427,902
21	REPLACE AUDIX WITH UNITY	420,705
22	CONSTRUCTION ACCOUNTING CAPITAL	408,114
23	HCC RESERVOIR DISCHARGE	397,474
24	HELLS CANYON COMPLEX BOTANICAL	382,170
25	REL - FLOW MODELING	378,930
26	NEW KUNA 138KV STATION	374,205
27	HCC RELICENSING PROCESS/DRAFT	369,227
28	HELLS CANYON COMPLEX MULE DEER	363,683
29	BOBN0204 REPLACE 202A	359,514
30	HELLS CANYON COMPLEX - RELICEN	353,449
31	FISHERIES-HCC WHITE STURGEON	338,052
32	BRDY-BORA LINE RELAY UPGRADE	333,892
33	PAET-013 ADD RIVER CROSSING	333,673
34	UNIT #2 OR #3 REWIND	324,822
35	HELLS CANYON COMPLEX TERR. PRE	315,301
36	OBPR0103-INSTALL DIGITAL MW	306,796
37	WATER QUALITY-SNAIL DELISTING	305,008
38	SNAIL CONSERVATION PLAN-FY2002	297,177
39	FISHERIES-HCC ANADROMOUS FISH	293,255
40	CLOVERDALE-BETHEL COURT-WYE 13	285,125
41	VALMY 24885 3600 & 3601 PCB	274,388
42	LINES CONSTRUCTION - CAPITAL	268,882
43	TOTAL	92,481,654

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/2003	Year of Report Dec. 31, 2002

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	REL - SEDIMENT PROJECTS	264,557
2	BROWNLEE-OXBOW 230KV UPGRADE	263,751
3	VALMY 24047 U1 SUPERHEATER TUB	258,308
4	ROLLUP RELIC COST BLISS	257,488
5	IDAHO 252 ACCOUNT ADJUSTING	254,889
6	CAPITAL OVERHEADS FOR CADD	251,842
7	ROLLUP RELIC COST SHOSHONE FALLS	249,694
8	HBMW DIGITAL MW PROJECT	247,835
9	FISHERIES-HCC REDBAND TROUT	247,233
10	BOBN 230KV SERIES CAPACITOR	246,407
11	BOARDMAN UNDISTRIBUTED WORK ORDER	246,300
12	BRIDGER 2002C061 U 1 2 & 3 COA	244,034
13	EMS COMPUTERS FOR DISPATCH	242,600
14	WESR R061 - REWIND 69 KV REGUL	235,890
15	REPLACE COMPAQ 2500 SERVERS	235,090
16	VALMY 25499 #2 COOLING TOWER	226,898
17	HAILEY TEAM CAP OH WORK ORDER	226,162
18	SALMON DIESEL CONTROL AND GOV.	225,807
19	IVRU DEVELOPMENT - CAPITAL WORK ORDER	225,199
20	WATER QUALITY-BASELINE MONITOR	222,407
21	HELLS CANYON COMPLEX CULTURAL	221,844
22	TERY - STUDY & SCOPE	217,006
23	TRANSFER REAL TIME TRADING FUN	216,595
24	BORA-BRDY LINE RELAY UPGRADE	215,869
25	DATA CENTER CABLING PROJECT	207,677
26	VALMY 22601 #1 BURNER MANAGMEN	206,799
27	ROLLUP RELIC COST LOWER SALMON	205,961
28	STATION APP 2002 LAB EQUIPMENT	205,366
29	HAILEY OPERATIONS DESIGN/CONST	199,807
30	BLPR0104-INSTALL DIGITAL MW	195,422
31	SBMW0102-INSTALL DIGITAL MW	194,817
32	BSPO-ADD MICROWAVE COMMUNICATION	193,829
33	BEACON LIGHT SUBSTATION	192,134
34	DONN T131 - REWIND FAILED TRAN	191,761
35	DUFN0201-REPLACE 101Z	189,210
36	GOSHEN C341 REPLACEMENT	188,837
37	TOOL EXP TRANS TO CONST	188,428
38	BDSS - REWIND TRANSFORMER IPCO	188,257
39	MOBILE #6 REPAIR WORKORDER	187,980
40	GOODING TEAM CAP OH WORK ORDER	182,875
41	STAR0101 PURCHASE PROPERTY FOR	179,255
42	MULTIFUNCTIONAL COPIERS	177,692
43	TOTAL	92,481,654

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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	LSMW DIGITAL MW PROJECT	177,234
2	DELIVERY CAPITAL OVERHEADS	176,317
3	INDUSCONNECT FRAMEWORK	175,000
4	LNDN INSTALL DCC IN STATION	172,971
5	ADAMSFAM TEAM CAP OH WORK ORDE	172,264
6	WATER QUALITY-HCC 401/TMDL-FY2	171,916
7	BOBN DIGITAL MW PROJECT	170,588
8	KUNA BUY PROPERTY FOR NEW KUNA	170,521
9	BOC/M&E REMODEL '02	169,945
10	ROLLUP RELIC COST C J STRIKE	168,086
11	REPLACE DONN-KPRT 1 SKBU RELAY	167,617
12	MIDROSE SUBSTATION- ACQUIRE AN	167,328
13	FRMT - SCOPE FOR IMPROVED RELI	166,832
14	SUN VALLEY CO.	164,762
15	GARY INSTALL DCC IN STATION	164,130
16	TWINWEST TEAM CAP OH WORK ORDE	164,041
17	PICABO 450 MHZ RADIO REPLACEME	163,626
18	IPCO/WESR-012/REBUILD/UPGRADE	159,992
19	NEW UNIT 8368 - ETHAN MORGAN	159,905
20	HELLS CANYON COMPLEX	159,869
21	MPSN0201-RTU REPLACEMENT	158,640
22	BRIDGER 2002C017 SOOTBLOWER CO	156,715
23	VALMY 25025 #2 BURNER NOX IMPR	154,767
24	BDSS - REWIND TRANSFORMER IPCO	153,585
25	POMW-SCOPE ADDING COMMUNICATION	153,029
26	ENVIRO DATA BASE DEVELOPMENT	152,394
27	FISHERIES-HCC INSTREAM FLOW	150,036
28	DELIVERY PC'S 2002	149,382
29	CONSULTING FEES FOR MERIDIAN	149,327
30	NAMPA HOUSE PURCHASE	149,228
31	HELLS CANYON COMPLEX NON-GAME	147,961
32	FERC UNLICENSE MIDPOINT BORAH	143,555
33	BOBN GRVE LINE PROTECTION	140,849
34	OREGON REAUTHORIZATION - HELLS	139,835
35	VARI0201 450 MHZ RADIO REPLACE	139,480
36	ADIC UPGRADE	138,775
37	BRIDGER 2001C004 U2 COUTANT	138,699
38	IPCO-TFSN-014 2002 CABLE REPLACE	137,026
39	WATER QUALITY-HCC MITIGATION	136,043
40	BDSS- REWIND IPCO#366-01 TRANS	135,701
41	FICON CHANNELS	134,531
42	KUNA-KUNA JCT. EASEMENTS	133,276
43	TOTAL	92,481,654

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/2003	Year of Report Dec. 31, 2002

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	REL - GEOMORPHOLOGY	132,753
2	UPGRADE DATA CTR. SWITCHES	130,459
3	SECURE ACCESS MANAGEMENT (SSO)	130,191
4	PURCHASE GPS UNITS FOR FEEDER	129,446
5	BOISE BENCH SECURITY	128,418
6	FISHERIES-HCC RESIDENT FISH-FY	128,298
7	IPCO-CITY OF KETCHUM-WARM SPRINGS	126,665
8	UPGRADE BOC & M & E	126,549
9	BOULDER SUBSTATION TRANSMISSION	124,529
10	REL - BANK STABILIZATION	123,563
11	PASB DIGITAL MW PROJECT	122,440
12	LINE #470, 2ND 138KV LINE	119,995
13	MNJ1 REPLACE 101A PCB	119,736
14	IPCO-LINE 233 REFURBISH WEISER	119,322
15	BRIDGER 2001C084 AIR BELTS	117,866
16	BOBN0201-BUILD BLAST WALL	117,759
17	VALMY 22602 #2 REHEAT TUBE	117,732
18	FISHERIES-PAHSIMEROI CAPITAL	117,678
19	CORRECTION WORK ORDER FOR BOC	117,546
20	VTRY INSTALL DCC IN STATION	117,385
21	FINANCE PC'S, PRINTERS, SCANNE	116,739
22	ACES HARDWARE UPGRADE	116,631
23	TFSB DIGITAL MW PROJECT	116,477
24	BRIDGER 2001C004 U2 & 3 BURNER	115,493
25	WEB TEAM SERVER	112,077
26	BOBN CONSOLIDATION REMODEL	111,885
27	TERMINAL SERVER/CITRIX	111,630
28	TFEAST TEAM CAP OH WORK ORDER	111,513
29	PHOENIX PROJECT: AM/FM/OMS	111,434
30	MINI CASSIA TEAM CAP OH WORK	110,731
31	TSP #3 UPGRAGE COMPLETION	110,419
32	EAGL TO STAR TRANSMISSION LINE	109,708
33	BOISE AIR TERMINAL INSTALL	109,334
34	BSMW-NEW MICROWAVE RELAY SITE	107,421
35	IPCO: CAMBRIDGE - MCCALL 69KV	106,674
36	JMSN-CWVY 69KV, ADD SECTIONALI	105,781
37	CRANE CREEK 011 LETHA AREA REB	103,903
38	VALMY 22594 U2 GEN / EXCITOR	103,327
39	IPCO*LINE #701-POWDER RIVER	103,171
40	IPCO-MORA-045 F-47,F-45 & F-45	102,866
41	MEDIA MOSAIC E-LEARNING PROJECT	102,540
42	VALMY 20170 SERVICE AIR SYSTEM	102,394
43	TOTAL	92,481,654

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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	TOOL CORRAL USE ONLY 2002	101,478
2	JNTA-DWSY 69KV, SECTIONALIZER	101,151
3	OTHER MINOR WORK ORDERS	11,177,400
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43	TOTAL	92,481,654

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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	1,202,919,298	1,202,919,298		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	85,174,683	85,174,683		
4	(413) Exp. of Elec. Plt. Leas. to Others				
5	Transportation Expenses-Clearing	3,041,785	3,041,785		
6	Other Clearing Accounts				
7	Other Accounts (Specify, details in footnote):				
8	Fuel Stock	159,701	159,701		
9	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 8)	88,376,169	88,376,169		
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired	23,842,021	23,842,021		
12	Cost of Removal	2,286,092	2,286,092		
13	Salvage (Credit)	4,446,299	4,446,299		
14	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 11 thru 13)	21,681,814	21,681,814		
15	Other Debit or Cr. Items (Describe, details in footnote):				
16					
17	Balance End of Year (Enter Totals of lines 1, 9, 14, 15, and 16)	1,269,613,653	1,269,613,653		
	Section B. Balances at End of Year According to Functional Classification				
18	Steam Production	434,025,860	434,025,860		
19	Nuclear Production				
20	Hydraulic Production-Conventional	236,498,187	236,498,187		
21	Hydraulic Production-Pumped Storage				
22	Other Production	2,527,421	2,527,421		
23	Transmission	185,425,734	185,425,734		
24	Distribution	351,657,228	351,657,228		
25	General	59,479,223	59,479,223		
26	TOTAL (Enter Total of lines 18 thru 25)	1,269,613,653	1,269,613,653		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

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

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	Idaho Energy Resources Company			
2	Common Stock	02/01/74		500
3	Capital contributions			2,462,594
4	Equity in earnings			10,111,568
5				
6	Subtotal Idaho Energy Resources			12,574,662
7				
8				
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40				
41				
42	Total Cost of Account 123.1 $ 2,463,094		TOTAL	12,574,662

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

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

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
		500		2
		2,462,594		3
9,532,971	7,000,000	12,644,539		4
				5
9,532,971	7,000,000	15,107,633		6
				7
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9,532,971	7,000,000	15,107,633		42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	8,726,387	6,942,920	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)	9,818,076	9,613,389	
8	Transmission Plant (Estimated)	3,280,507	2,756,570	
9	Distribution Plant (Estimated)	6,779,958	5,697,117	
10	Assigned to - Other (provide details in footnote)	827,183	871,591	
11	TOTAL Account 154 (Enter Total of lines 5 thru 10)	20,705,724	18,938,667	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)	2,573,824	2,519,780	Electric
16				
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	32,005,935	28,401,367	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2003 No. (d)	2003 Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2004		2005		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
								1
								2
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1	None					
2						
3						
4						
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12						
13						
14						
15						
16						
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18						
19						
20	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21	None					
22						
23						
24						
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47						
48						
49	TOTAL					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/2003	Year of Report Dec. 31, 2002

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets which are created through the rate making actions of regulatory agencies (and not includable in other accounts)
2. For regulatory assets being amortized, show period of amortization in column (a)
3. Minor items (5% of the Balance at End of Year for Account 182.3 or amounts less than $50,000, whichever is less) may be grouped by classes.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Debits (b)	CREDITS Account Charged (c)	CREDITS Amount (d)	Balance at End of Year (e)
1	Meridian Periodic Payments - IPUC		401	886,307	886,307
2	order #25533(amort period 1/96 thru 12/03)				
3					
4	Meridian Initial Buyout - ID IPUC order #25533		401	490,681	537,772
5	(amort period 1/96 thru 12/03)				
6					
7	Meridian Periodic Payments - OR order #96-166		401	43,833	43,833
8	(amort period 1/96 thru 12/03)				
9					
10	Postretirement Benefits - IPUC order #25550		401	544,800	1,135,000
11	(amort period 2/95 thru 01/05)				
12					
13	Reorganization Costs - IPUC order 26216		401	754,057	2,262,169
14	OPUC order #95-1262 (amort 01/96 thru 12/05)				
15					
16	Regulatory Unfunded Accumulated Deferred Income	121,252,607	282	3,151,095	327,933,448
17					
18	Power Cost Adjustment - IPUC order #27516	236,452,723		274,581,080	83,162,307
19	(amort period 5/01 thru 05/02)				
20					
21	Oregon pre-1994 Conservation -OPUC		401	55,560	46,300
22	# 98448 (amort period 10/98 thru 10/03)				
23					
24	Photovoltaic Startup IPUC order #25880		401	23,808	49,600
25	(Amort period 2/96 thru 1/06)				
26					
27	Idaho - Demand Side Management - IPUC order		401	3,242,604	24,319,559
28	#27660 (amort period 7/98 thru 6/10)				
29					
30	FAS133 Mark to Market	683,306		48,373,473	91,235
31					
32	FAS112 Post Employment Benefits		401	371,508	774,044
33	(Amort period 2/95 thru 1/05)				
34					
35	Astaris Buyback Program - Idaho	41,167,983	182	76,253,930	27,160,315
36					
37	Irrigation Deferral Order #29026	12,049,057			12,049,057
38	(Amort period 4/03 thru 3/04)				
39					
40	PCA Industrial Customers Order #29065	3,744,467			3,744,467
41	(Amort period 4/03 thru 3/04)				
42					
43					
44	TOTAL	431,992,523		411,422,065	499,305,339

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets which are created through the rate making actions of regulatory agencies (and not includable in other accounts)
2. For regulatory assets being amortized, show period of amortization in column (a)
3. Minor items (5% of the Balance at End of Year for Account 182.3 or amounts less than $50,000, whichever is less) may be grouped by classes.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Debits (b)	CREDITS Account Charged (c)	CREDITS Amount (d)	Balance at End of Year (e)
1	Excess Power Amortization - Oregon	14,290,285	401	1,135,663	14,171,691
2	(Amort period $1.6 mill per yr until full amort)				
3					
4	Security Costs 2001-2002	891,420			891,420
5	(Amort period 1/03 thru 12/07)				
6					
7	Minor items (6)	1,460,675	Various	1,513,666	46,815
8					
9					
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40					
41					
42					
43					
44	TOTAL	431,992,523		411,422,065	499,305,339

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

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Account 182 $  78,530,832
Account 557   195,876,681
Account 431       173,567
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Schedule Page: 232 Line No.: 30 Column: c

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Account 232 $ 40,491,221
Account 253    7,882,252
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Regional Transmsn Org - (RTO)	1,218,855	617,318		66,830	1,769,343
2						
3	Advance prepaid coal royalties	2,740,662	4,230,000	131	4,422,810	2,547,852
4						
5	Benefits plan - intangible asst	2,073,981	92,120			2,166,101
6						
7	Security Plan	30,606,683	2,606,190		6,320,010	26,892,863
8						
9	American Falls bond refinance	336,998	5	401	14,446	322,557
10						
11	Expense of Issue	105,666	37,688	146	143,354	
12						
13	Company owned Life Insurance	8,994,825	580,804		1,169,168	8,406,461
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 -	6,192,413	44,402	232	7,395	6,229,420
20	right of way costs					
21						
22	CSPP receivable	3,234,334		143	972,217	2,262,117
23						
24	American Falls - bond refinance	1,111,558		401	47,638	1,063,920
25	(35 year amortization)					
26						
27	Security Plan Trust	16,755,157	15,057,191		31,812,348	
28						
29	Shelf Registration	484,887	1,655,481		83,069	2,057,299
30						
31	Floating Rate Note	236,424	131,636		363,372	4,688
32						
33	Irrigation Lost Revenue		12,015,187			12,015,187
34						
35	Minor Items & Job Orders (6)	-97,432	21,332,705	Various	21,387,833	-152,560
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	105,580,011				97,170,248

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

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Account 131  $   306
Account 232   66,524
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Schedule Page: 233 Line No.: 7 Column: d

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Account 128 $  140,737
Account 131    909,990
Account 186  3,868,485
Account 426  1,400,798
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Schedule Page: 233 Line No.: 13 Column: d

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Account 131 $ 554,710
Account 426   614,458
```

Schedule Page: 233 Line No.: 27 Column: d

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Account 128 $ 20,621,615
Account 131    2,814,857
Account 186      480,009
Account 211    2,643,514
Account 232      203,101
Account 283    1,552,024
Account 419      119,344
Account 421    1,493,324
Account 426    1,884,560
```

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

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Account 131        40
Account 186    83,029
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Schedule Page: 233 Line No.: 31 Column: d

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Account 232        197
Account 431    363,175
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Contributions in Aid of Construction	3,940,601	3,758,549
3	FASB 109 Accounting	41,289,868	41,012,859
4			
5			
6			
7	Other		
8	TOTAL Electric (Enter Total of lines 2 thru 7)	45,230,469	44,771,408
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify) See note 1 Below	-4,655,167	-7,866,289
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	40,575,302	36,905,119

Notes

(1) Other:

	Beginning Balance	Ending Balance
Security Plan	$ 7,331,077	$ 8,284,729
Bonus Deferral	(5,331,091)	(5,285,937)
Contigent Liability-Accident Reserve	98,063	0.00
' Contigent Liability-Marketing	4,197,075	4,197,075
FERC Settlement Reserve	0.00	1,537,557
SMSP-Market Change of Rabbi Investments	0.00	384,217
Donations Not Deducted in 2001	347,444	0.00
Idaho Public Utilities-Rate refund	1,360,302	1,020,870
Mark to Market-Energy Trading	(21,425,081)	(27,667,943)
Meridian Gold Contributions	309,646	286,422
Micron-CIAC	3,503,147	3,226,473
' Minimum Pension Liability	2,592,190	3,856,760
Non VEBA Pension & Benefits	888,492	977,195
Other EE's Long Term Deferred Comp	100,107	203,726
Pioneer Land (write down)	45,502	45,502
Post Retirement benefits	(335,561)	(456,827)
Restricted Stock Plan	659,915	449,871
Seattle City Light-CIAC	176,070	144,175
SFAS112-Post Employment Benefits	731,369	850,104
Start Up and Organization Costs	96,168	79,742

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

CAPITAL STOCKS (Account 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Account 201			
2	Common Stock registered on New York	50,000,000	2.50	
3	and Pacific Stock Exchange			
4	Total Common Stock	50,000,000	2.50	
5				
6	Account 204			
7	4% Preferred Stock	215,000	100.00	104.00
8				
9	Serial Preferred Stock:			
10	7.68% Series (cumulative)	150,000	100.00	102.97
11				
12	7.07% Series (cumulative)	250,000	100.00	103.53
13				
14	Total Preferred Stock	615,000	300.00	
15				
16				
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CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
37,612,351	94,030,878					2
						3
37,612,351	94,030,878					4
						5
						6
133,927	13,392,700	9,945	172,354			7
						8
						9
150,000	15,000,000					10
						11
250,000	25,000,000					12
						13
533,927	53,392,700	9,945	172,354			14
						15
						16
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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	Balance January 1, 2001	764,225
7		
8	4% Preferred Stock (par value $100):	
9	Par Value of retired Capital Stock - 9,945 shares	994,500
10	Transfer Premium on Capital Stock (account 207) - 9,945 shares	12,925
11	Transfer Capital Stock expenses (account 214) - 9,945 shares	-23,329
12	Cost of retired Capital Stock (account 217) - 9,945 shares	-824,728
13		
14	Write off for retirement of Auction Preferred stock	-800,360
15		
16	Account 211	0
17		
18		
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39		
40	TOTAL	123,233

Schedule Page: 253   Line No.: 16   Column: b

The 2001 balance for the Minimum Pension Liability for Deferred Compensation and Unrealized Gains and Losses on Available-for-Sale Securities (OCI - 4,508,136 and 789,057) was reclassified to Account 219.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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	2,071,924
2		
3	Preferred Stock:	
4	4% (1)	314,050
5	7.68% Serial	33,859
6	7.07% Serial	290,282
7	Flexible Auction Series (2)	
8		
9		
10	Explanation of Changes during the year:	
11		
12		
13		
14	(1) Charge off amount of capital stock expense applicable to retirement of 9,945 shares	
15	account 210 $ 172,354	
16		
17	(2) Flexible Auction Series was redeemed in August 2002	
18		
19		
20		
21		
22	TOTAL	2,710,115

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Account 221:		
2	First Mortgage Bonds:		
3	6.85% Series due 2002	27,000,000	240,493
4			
5	6.40% Series due 2003	80,000,000	667,636
6			
7	7.38% Series Due 2007	80,000,000	807,871
8			
9	7.20% Series due 2009	80,000,000	572,246
10			
11	8.00% Series due 2004	50,000,000	463,337
12			400,000 D
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	7.50% Series due 2023	80,000,000	767,636
19			614,400 D
20			
21	8 3/4% Series due 2027	50,000,000	563,337
22			187,500 D
23			
24	4.75% Series due 2012(Idaho Commission Case ICP-E-01-27,	100,000,000	944,356
25	Oregon Commission UF4181,Wyoming Docket #20005-ES-01-23 (11-15-02)		1,047,617 D
26			
27	6.00% Series due 2032(Idaho Commission Case ICP-E-01-27,	100,000,000	1,069,356
28	Oregon Commission UF4181,Wyoming Docket #20005-ES-01-23(11-15-02)		543,244 D
29			
30			
31			
32			
33	TOTAL	1,052,384,184	15,973,393

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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			
2	Pollution control Revenue Bonds		
3			
4			
5	8.30% Valmy due 2014	49,800,000	2,235,221
6			
7			
8	6.05% Series 96A due 2026	68,100,000	571,895
9			471,252 D
10			
11	Series 96B due 2026	24,200,000	124,587
12			
13			
14	Series 96C due 2026	24,000,000	123,561
15			
16	Port of Morrow Variable due 2027	4,360,000	188,545
17			
18	Subtotal Account 221	997,460,000	15,973,393
19			
20	Account 224:		
21	Other Long-Term Debt		
22			
23	Bond Guarantee - American Falls	21,425,000	
24			
25	Bond Guarantee - American Falls	19,885,000	
26			
27	Note Guarantee - Milner Dam	11,700,000	
28	REA Notes	1,914,184	
29	Subtotal Account 224	54,924,184	
30			
31	Account 222 - Reacquired Bonds		
32	Account 223 - Advances from Associated Companies		
33	TOTAL	1,052,384,184	15,973,393

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
10/02/96	10/01/02	10/02/96	10/01/02		1,387,125	3
						4
04/28/93	05/01/03	04/28/93	05/01/03	80,000,000	5,120,000	5
						6
12/1/00	12/1/07	12/1/00	12/1/07	80,000,000	5,904,000	7
						8
11/23/99	12/1/09	1/1/00	1/1/10	80,000,000	5,760,000	9
						10
03/25/92	03/15/04	03/21/92	03/15/04	50,000,000	4,000,000	11
						12
						13
09/09/98	09/09/05	09/09/98	09/09/05	60,000,000	3,498,000	14
						15
03/02/01	03/02/11	03/02/01	03/02/11	120,000,000	7,920,000	16
						17
04/28/93	05/01/23	04/28/93	05/01/23	80,000,000	6,000,000	18
						19
						20
03/25/92	03/15/27	03/25/92	03/15/27		911,458	21
						22
						23
11/15/02	11/15/12	11/15/02	11/15/12	100,000,000	606,944	24
						25
						26
11/15/02	11/15/32	11/15/02	11/15/32	100,000,000	766,667	27
						28
						29
						30
						31
						32
				953,229,728	51,127,384	33

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
						4
12/20/84	12/01/14	12/20/84	12/01/14	49,800,000	4,133,400	5
						6
						7
07/25/96	07/15/26	07/25/96	07/15/26	68,100,000	4,120,050	8
						9
						10
07/25/96	07/15/26	07/25/96	07/15/26	24,200,000	431,290	11
						12
						13
07/25/96	07/15/26	07/25/96	07/15/26	24,000,000	416,022	14
						15
5/17/00	2/1/27	5/17/00	2/1/07	4,360,000	114,862	16
						17
				920,460,000	51,089,818	18
						19
						20
						21
						22
03/01/90						23
						24
4/26/00	2/1/25			19,885,000		25
						26
02/10/92				11,700,000		27
				1,184,728	37,566	28
				32,769,728	37,566	29
						30
						31
						32
				953,229,728	51,127,384	33

Name of Respondent	This Report is:	Date of Report	Year of Report
Idaho Power Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 04/30/2003	Dec 31, 2002

FOOTNOTE DATA

Schedule Page: 256 Line No.: 3 Column: h

The 6.85% Series was redeemed in October 2002.

Schedule Page: 256 Line No.: 21 Column: h

The 8.75% Series was redeemed in March 2002

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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

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

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	88,920,696
2		
3		
4	Taxable Income Not Reported on Books	
5		19,150,235
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		161,061,834
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		32,165,730
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		17,553,177
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	
28	Show Computation of Tax:	219,413,857
29	Tenative Federal Tax 219,413,857 @ 35%	76,794,850
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

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

Construction ADV-252	$ -520,150
CIAC as taxable inc to closed plant	19,136,699
Avoided cost int cap	1,809,848
Retirements-record tax gain/loss	-750,000
CIAC as taxable inc in Acct 107	210,557
Royalty income	109,150
CIAC-Meridian Gold	-59,206
CIAC-Micron-DRAM	-705,351
CIAC-Seattle City Light-New	-81,312
Total	$ 19,150,235

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

Total Federal & State taxes Ded on Books	$ -4,177,535
Bad debt expense	66,346
Gain/Loss on Reacquired Debt-deferred	868,392
SFAS 112-Post-Emply Ben	302,701
Overaccrued Vacation	436,118
Prin portion--air lease	138,915
Injuries & Damages	436,041
Excess benefits plan	-1,128,192
Directors Fees Deferred	208,837
Capitalized Overheads	-10,000,000
Pension Accrual	-74,250
Meals (50% Non-Deductible) charded to R.E.	300,000
Milner Falling Water-Rev Accrual	264,100
Amortization of Acccount 114	-22,723
Oregon Operating Property Tax Adjustment	52,378
Nonveba Pension & Benefits	226,140
PCA Expense Deferral	167,849,679
Post Retiree Benefit-FAS106-	544,800
Sun Valley Fac--Rev Amort	12,328
Restricted Stock Plan-Comp	-535,486
Cont Liability-Accident Reserve	-250,000
Other Employee's LT Deferred Comp	264,166
Bonus Deferral	-275,558
Ferc Settlement Reserve	3,919,840
SEC Plan Net Ins Costs	-1,097,786
SMSP-Market Change of Rabbi Investments	979,519
EDC-Unrealized Gain/Loss from Rabbi Trust	5,571
Nondeductible Political Expense	250,000
SEC Plan Benefit Accrual	2,431,236
Nondeductible Fines & Penalties	-109,672
Nondeductible Political Exp	100,000
StartUp & Organizational Costs	-38,300
Donations Not Deducted this Year	-885,771
Total	$ 161,061,834

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

Gain on Sale of BOC	$ 31,970
Other Regulatory Liabilities	865,346
Reverse Equity Earnings of Subsidiaries	10,368,122
Allowance for OFUDC	333,060
Allowance for BFUDC	2,374,773
Security Plan-Insurance Proceeds	2,276,941
Mark to Market-Energy Trading	15,915,518
Total	$ 32,165,730

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

VEBA-Post Retirement Benefits	$ 268,838
Depreciation for Tax GT or LT book	-11,879,213
Conservation Programs	-3,882,831
Nevada Operation Property Tax Adjustment	-15,368
Removal Costs	2,327,303
Repair Allowance	7,000,000
Oregon Excess Power Supply Costs	-693,934
American Falls-Unamortized Debt Expense	-47,638
Gain/Loss on Reacquired Debt	2,080,713
Meridian Contract Buyout	-384,569
Reorganization Costs	-754,057
Misc 186 Adjustments	-247,718
Software costs Misc-107	700,000
Ferc Order 2000 Costs	550,488
Photovoltaic Startup Costs	-23,808
Research & Develop Deduct	5,000,000
Incremental Security Costs Deducted	830,898
PP Ins & Other Expense (1 Yr or Less)	2,764,741
COLI_Tax Adjustment from Books	-549,573
Oregon Nonoperation Property Tax Adjustment	107
Depreciation Adjustment-Non Op-Other Property	32,192
Dividends Paid Ded Pub Utility	79,000
State Income Tax Deducted on Federal Return	14,397,606
Total	$ 17,553,177

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1	Federal:					
2	Income	-16,024,609		69,449,702	-25,281,710	
3	Social Security - (FOAB)			8,284,494	8,284,489	
4	Unemployment	-722		102,660	102,660	
5	Environmental					
6	Subtotal Federal	-16,025,331		77,836,856	-16,894,561	
7						
8	State of Idaho:					
9	Property	5,600,298		12,278,415	12,166,651	
10	Income	-6,369,918		7,439,026	3,958,608	
11	KWH	95,437		1,407,846	1,413,250	
12	Unemployment			190,269	190,270	
13	Regulatory Commission			1,714,256	1,714,256	
14	Motor Vehicle License					
15	Business License - Sho Ban		150	150	150	
16	Subtotal Idaho	-674,183	150	23,029,962	19,443,185	
17						
18	State of Oregon					
19	Property		1,032,158	2,021,362	1,969,091	
20	Income	39,624		808,924	10	
21	Regulatory Commission			93,470	93,470	
22	Unemployment			8,586	8,900	
23	Franchise	112,265		452,904	456,242	
24	Subtotal Oregon	151,889	1,032,158	3,385,246	2,527,713	
25						
26	State of Montana:					
27	Property	41,820		85,799	84,768	
28	Subtotal Montana	41,820		85,799	84,768	
29						
30	State of Nevada:					
31	Property	265,787	483,973	964,014	956,330	
32	Unemployment			63	63	
33	Mountain City License			100	100	
34	Elko County Franchise	588		-588		
35	Regulatory Commission			1,536	1,536	
36	Business Tax					
37	Subtotal Nevada	266,375	483,973	965,125	958,029	
38						
39						
40						
41	TOTAL	-15,067,246	1,516,281	98,040,412	7,271,899	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1	State of Wyoming					
2	Corporate License			2,856	2,856	
3	Property	587,216		922,617	1,048,524	
4	Subtotal Wyoming	587,216		925,473	1,051,380	
5						
6	misc states franchise			50	78	
7						
8	Other States Income	584,968		350,395	101,307	
9	Payroll Adjustment			-8,538,494		
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	-15,067,246	1,516,281	98,040,412	7,271,899	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/2003	Year of Report Dec. 31, 2002

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
78,706,803		75,166,821			-5,717,119	2
5		8,284,494				3
-722		102,660				4
						5
78,706,086		83,553,975			-5,717,119	6
						7
						8
5,712,062		12,278,415				9
-2,889,500		8,445,646			-1,006,620	10
90,033		1,407,846				11
-1		190,269				12
		1,714,256				13
						14
	150	150				15
2,912,594	150	24,036,582			-1,006,620	16
						17
						18
	979,887	2,021,362				19
848,538		895,701			-86,777	20
		93,470				21
-314		8,586				22
108,928		452,904				23
957,152	979,887	3,472,023			-86,777	24
						25
						26
42,851		85,799				27
42,851		85,799				28
						29
						30
258,102	468,605	964,014				31
		63				32
		100				33
		-588				34
		1,536				35
						36
258,102	468,605	965,125				37
						38
						39
						40
84,172,122	1,448,642	104,885,639			-6,845,227	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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
		2,856				2
461,309		922,617				3
461,309		925,473				4
						5
-28		50				6
						7
834,056		385,106			-34,711	8
		-8,538,494				9
						10
						11
						12
						13
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						17
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						34
						35
						36
						37
						38
						39
						40
84,172,122	1,448,642	104,885,639			-6,845,227	41

FOOTNOTE DATA

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

409.2 $ -5,679,551
107 -37,568

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

409.2 $ -1,006,620

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

409.2 $ -86,777

Schedule Page: 262.1 Line No.: 8 Column: l

409.2 $ -34,711

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%	2,020,362				158,018	
4	7%						
5	10%	42,475,810				2,178,434	
6		1,505,953				25,053	
7		22,013,798	255	2,722,422	411	817,228	
8	TOTAL	68,015,923		2,722,422		3,178,733	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Line 6 col A 11%						
11							
12	State of Idaho	22,013,798	255	2,722,422	411	817,228	
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
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48							

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

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
1,862,344	12.79		3
			4
40,297,376	19.50		5
1,480,900	60.11		6
23,918,992	26.94		7
67,559,612			8
			9
			10
			11
23,918,992			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
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			47
			48

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

OTHER DEFFERED CREDITS (Account 253)

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

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Point to Point Transmission Study	536,407	131	875,012	1,244,757	906,152
2						
3	FTV		400	750,000	1,150,000	400,000
4						
5	FASB 133 Mark to Market	7,253,478	1823	30,550,025	23,296,547	
6						
7	Customer Level Pay	2,078,918	142	1,421,761	2,481,032	3,138,189
8						
9	US Airforce Photovoltaic Generator	70,247	431	1,000	33,809	103,056
10						
11	Security Plan	19,817,999		2,506,956	3,810,000	21,121,043
12						
13	FERC Settlement Reserve				3,919,840	3,919,840
14						
15	Milner Falling Water	2,400,557			264,100	2,664,657
16						
17	Postretirement Benefits	3,010,101	401	469,200	400,394	2,941,295
18						
19	Benefit Plan - Minimum Liability	8,682,496			3,316,007	11,998,503
20						
21	Directors Deferred Compensation	2,965,553	131	239,161	447,997	3,174,389
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						
47	TOTAL	46,815,756		36,813,115	40,364,483	50,367,124

Schedule Page: 269 Line No.: 11 Column: c

Account 232	$ 2,265,408
Account 241	241,265
Account 401	283

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/2003	Year of Report Dec. 31, 2002

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

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities			
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)			
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)			
18	Classification of TOTAL			
19	Federal Income Tax			
20	State Income Tax			
21	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
							3
							4
							5
							6
							7
							8
							9
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							20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	235,515,614	9,297,208	31,460,329
3	Gas			
4	Other than Liberalized Depr	224,246,829	3,253,547	348,100
5	TOTAL (Enter Total of lines 2 thru 4)	459,762,443	12,550,755	31,808,429
6	Non-Operating Property	249,872		
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	460,012,315	12,550,755	31,808,429
10	Classification of TOTAL			
11	Federal Income Tax	386,747,360	12,675,776	31,808,429
12	State Income Tax	73,264,955	-125,021	
13	Local Income Tax			

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits Account Credited (g)	Debits Amount (h)	Credits Account Debited (i)	Credits Amount (j)	Balance at End of Year (k)	Line No.
							1
						213,352,493	2
							3
		182		182	118,101,511	345,253,787	4
					118,101,511	558,606,280	5
12,627	278					262,221	6
							7
							8
12,627	278				118,101,511	558,868,501	9
							10
10,535	232				101,533,180	469,158,190	11
2,093	46				16,568,331	89,710,312	12
							13

NOTES (Continued)

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

Back in 1999 the ending balance on page 275 line 2 was misstated by $100,000. This balance has been carried forward ever since 1999 and has had an error of $100,000 all these years.

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

	Col B	Col C	Col D	Col G	Col I	Col J	Col K
Repair	$729,985		$169,200				$560,785
Bridger	734,457		102,400				632,057
N. Valmy	1,116,266		76,500				1,039,766
FERC	7,024,671	343,692					7,368,363
CIAC	-4,116,321	1,323,507					-2,792,814
Software	700,000	155,674					855,674
R & D	8,225,834	1,430,674					9,656,508
FASB 109	209,831,937			182	182	118,101,511	327,933,448
Total	$224,246,829	$3,253,547	$348,100			$118,101,511	$345,253,787

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Bald Mountain	9,671		4,835
4	Meridian buyout contracts	320,166		150,847
5	Ferc Order 144A	-813,037		-115,100
6				
7				
8	Other	134,041,209	14,135,240	81,275,240
9	TOTAL Electric (Total of lines 3 thru 8)	133,558,009	14,135,240	81,315,822
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other	472,443		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	134,030,452	14,135,240	81,315,822
20	Classification of TOTAL			
21	Federal Income Tax	111,687,415	11,792,880	67,821,852
22	State Income Tax	22,343,037	2,342,360	13,493,970
23	Local Income Tax			

NOTES

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

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

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
						4,836	3
						169,319	4
						-697,937	5
							6
							7
		219	382,051	219		66,519,158	8
			382,051			65,995,376	9
							10
							11
							12
							13
							14
							15
							16
							17
4,141	42,815					433,769	18
4,141	42,815		382,051			66,429,145	19
							20
3,455	35,727		320,698			55,305,473	21
686	7,088		61,353			11,123,672	22
							23

NOTES (Continued)

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

	Col B	Col C	Col D	Col G	Col H	Col I	Col K
Loss Reacq Debt	$1,432,295		$340,627				$1,091,668
Conservation Prog	11,137,666	811,865	1,523,040				10,426,491
PCA Exp Deferral	113,604,610	12,372,170	78,211,206				47,765,573
PV Startup Costs	28,794		9,339				19,456
Post Employment	658,902		213,698				445,204
Reorg Costs	1,183,114		295,779				887,335
Incr Security Costs	6,454	325,920					332,373
FERC Order 2000	478,096	215,929					694,025
Oregon Excess Power	5,831,041	409,356	681,551				5,558,846
Unrealized Gain Mkt	-319,763			219	-382,051	219	-701,814
Total	$134,041,209	$14,135,240	$81,275,240		$-382,051		$66,519,158

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

	Col B	Col E	Col F	Col K
Advance Coal Royalties	$474,495	$6,326	$42,814	$438,007
Oregon non-Op Prop Tax Adj	784		1	783
Unrealized G/L from Rabbi Trust	-2,836	-2,185		-5,021
Total	$472,443	$4,141	$42,815	$433,769

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

1. Reporting below the particulars (Details) called for concerning other regulatory liabilities which are created through the rate-making actions of regulatory agencies (and not includable in other amounts)
2. For regulatory Liabilities being amortized show period of amortization in column (a).
3. Minor items (5% of the Balance at End of Year for Account 254 or amounts less than $50,000, whichever is Less) may be grouped by classes.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	DEBITS Account Credited (b)	DEBITS Amount (c)	Credits (d)	Balance at End of Year (e)
1	Idaho 1999 - NEEA (Nw energy efficiency act)	131	1,219,797		
2		254	609,332	728,760	2,367,578
3					
4	Demand Side Management Rider 29026	131	53,713		
5		142	83,686		
6		254	198,222		
7		401	121,201	1,808,295	1,351,473
8					
9	BPA Credit-Residential - Idaho	131	13,675		
10		142	19,235,702	19,646,178	992,235
11					
12	BPA Credit-Residential - Oregon	131	288		
13		142	724,406	762,592	60,743
14					
15	BPA Credit-Farm - Idaho	142	4,204,085	3,951,892	89,227
16					
17	BPA Credit-Farm - Oregon	142	215,366	210,166	4,486
18					
19	BPA Credit - Conservation	131	156,748		
20		254	264,156		448,490
21					
22	Pre94 Demand Side Management Order			235,024	235,024
23					
24					
25	Boise Operation Center	401	31,970		125,217
26					
27					
28	Unfunded Accumulated Deferred Income Tax	190	772,152	495,143	41,012,859
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41	TOTAL		27,904,499	27,838,050	46,687,332

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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 increases or decreases from previous year (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.

Line No.	Title of Account (a)	OPERATING REVENUES Amount for Year (b)	OPERATING REVENUES Amount for Previous Year (c)
1	Sales of Electricity		
2	(440) Residential Sales	305,827,216	260,251,206
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	286,812,049	233,620,438
5	Large (or Ind.) (See Instr. 4)	176,648,064	154,317,682
6	(444) Public Street and Highway Lighting	2,747,434	2,419,039
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	772,034,763	650,608,365
11	(447) Sales for Resale	55,031,087	219,966,420
12	TOTAL Sales of Electricity	827,065,850	870,574,785
13	(Less) (449.1) Provision for Rate Refunds		-1,823,627
14	TOTAL Revenues Net of Prov. for Refunds	827,065,850	872,398,412
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	3,355,823	3,255,111
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	19,213,988	17,954,524
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	17,411,759	18,703,506
22			
23			
24			
25			
26	TOTAL Other Operating Revenues	39,981,570	39,913,141
27	TOTAL Electric Operating Revenues	867,047,420	912,311,553

ELECTRIC OPERATING REVENUES (Account 400)

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 basis of classification in a footnote.)
5. See pages 108-109, Important Changes During Year, for important new territory added and important rate increase 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.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Amount for Year (d)	Amount for Previous Year (e)	Number for Year (f)	Number for Previous Year (g)	
				1
4,386,794	4,306,996	339,764	331,275	2
				3
5,253,004	4,772,190	67,622	66,646	4
3,225,781	3,924,637	115	115	5
28,489	27,202	327	255	6
				7
				8
				9
12,894,068	13,031,025	407,828	398,291	10
2,068,504	2,387,206			11
14,962,572	15,418,231	407,828	398,291	12
				13
14,962,572	15,418,231	407,828	398,291	14

Line 12, column (b) includes $ -168,653 of unbilled revenues.

Line 12, column (d) includes -1,757 MWH relating to unbilled revenues

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	440 - Residential Sales:					
2	01 - Residential	4,423,109	307,956,575	339,750	13,019	0.0696
3	03 - Residential-Mastered Metere	3,272	218,805	14	233,714	0.0669
4	84 - Residential-Net Metering	36	2,491			0.0692
5	15 - Dusk to dawn lighting	2,450	668,101			0.2727
6	Unbilled Revenues	-42,073	-3,018,756			0.0718
7	Total 440	4,386,794	305,827,216	339,764	12,911	0.0697
8						
9	442-Commercial & Industrial Sales					
10	07 - General service	287,633	22,816,411	33,599	8,561	0.0793
11	09 - General service	3,125,975	168,396,169	17,935	174,295	0.0539
12	10 - Large power winter service	77	45,918	3	25,667	0.5963
13	84 - General Service - Net Meter	14	750			0.0536
14	15 - Dusk to dawn lighting	3,801	933,664			0.2456
15	19 - Uniform rate contracts	2,159,231	94,711,656	111	19,452,532	0.0439
16	21 - Interruptible irrigation					
17	22 - Limited use Prairie Power	1	312	1	1,000	0.3120
18	24 - Irrigation Pumping	1,728,223	88,574,555	15,034	114,954	0.0513
19	25 - Irrigation Pumping -Time of	87,785	4,316,308			0.0492
20	40 - General service	15,478	1,170,532	1,050	14,741	0.0756
21	Commercial & Industrial & Unbill	1,070,567	82,493,838			0.0771
22	Total 442	8,478,785	463,460,113	67,733	125,180	0.0547
23						
24	444 - Public Street Lighting:					
25	32 - Shielded Streel Lighting	31	6,476	1	31,000	0.2089
26	40 - General service	780	59,096	130	6,000	0.0758
27	41 - Street lighting	18,347	2,230,645	132	138,992	0.1216
28	42 - Traffic control lighting	9,333	451,217	64	145,828	0.0483
29	Public Lighting					
30	Total 444	28,491	2,747,434	327	87,128	0.0964
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	12,911,644	773,721,299	0	0	0.0599
42	Total Unbilled Rev.(See Instr. 6)	-17,576	-1,686,536	0	0	0.0960
43	TOTAL	12,894,068	772,034,763	0	0	0.0598

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW) Average Monthly NCP Demand	Actual Demand (MW) Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Raft River Rural Electric	RQ	V6-44	9.421	9.421	8.412
2	City of Weiser	RQ	V6-32	9.212	9.212	8.517
3	AEP Service Corp.	SF	WSPP	0.000	0.000	0.000
4	Bonneville Power Administration	OS	WSPP	0.000	0.000	0.000
5	Bonneville Power Administration	SF	WSPP	0.000	0.000	0.000
6	BP Energy Company	OS	WSPP	0.000	0.000	0.000
7	BP Energy Company	SF	WSPP	0.000	0.000	0.000
8	Chelan Co PUD	SF	WSPP	0.000	0.000	0.000
9	Clatskanie PUD	OS	-	0.000	0.000	0.000
10	Clatskanie PUD	SF	-	0.000	0.000	0.000
11	Colton, City of	LF	84	0.000	0.000	0.000
12	Duke Energy Trading and Marketing	OS	WSPP	0.000	0.000	0.000
13	Dynegy Power Marketing, Inc.	SF	WSPP	0.000	0.000	0.000
14	Enron Power Marketing	SF	WSPP	0.000	0.000	0.000
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Enron Power Marketing (2)	SF	WSPP	0.000	0.000	0.000
2	Entergy-Koch Trading, LP	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	IDACORP Energy L.P.	SF	V6-48	0.000	0.000	0.000
9	IDACORP Energy L.P (2)	SF	V6-48	0.000	0.000	0.000
10	Mieco, Inc.	OS	WSPP	0.000	0.000	0.000
11	Mieco, Inc.	SF	WSPP	0.000	0.000	0.000
12	Morgan Stanley Capital Group Inc.	SF	WSPP	0.000	0.000	0.000
13	NorthWestern Energy, L.L.C.	OS	WSPP	0.000	0.000	0.000
14	NorthWestern Energy, L.L.C.	SF	WSPP	0.000	0.000	0.000
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
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LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Pacific Northwest Generating Cooper	OS	WSPP	0.000	0.000	0.000
2	PacifiCorp Inc.	OS	WSPP	0.000	0.000	0.000
3	PacifiCorp Inc.	SF	WSPP	0.000	0.000	0.000
4	Pinnacle West Capital Corporation	SF	WSPP	0.000	0.000	0.000
5	Portland General Electric Company	OS	WSPP	0.000	0.000	0.000
6	Portland General Electric Company	SF	WSPP	0.000	0.000	0.000
7	Powerex Corp.	OS	WSPP	0.000	0.000	0.000
8	Powerex Corp.	SF	WSPP	0.000	0.000	0.000
9	PPL Montana, LLC	OS	WSPP	0.000	0.000	0.000
10	PPL Montana, LLC	SF	WSPP	0.000	0.000	0.000
11	Public Service Co. of Colorado	OS	WSPP	0.000	0.000	0.000
12	Public Service Comp of New Mexico	OS	WSPP	0.000	0.000	0.000
13	Public Service Comp of New Mexico	SF	WSPP	0.000	0.000	0.000
14	Puget Sound Energy, Inc.	OS	WSPP	0.000	0.000	0.000
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Puget Sound Energy, Inc.	SF	WSPP	0.000	0.000	0.000
2	Reliant Energy Services, Inc.	SF	WSPP	0.000	0.000	0.000
3	Salt River Project	OS	WSPP	0.000	0.000	0.000
4	Seattle City Light	OS	WSPP	0.000	0.000	0.000
5	Seattle City Light	SF	WSPP	0.000	0.000	0.000
6	Sempra Energy Trading Corp	SF	WSPP	0.000	0.000	0.000
7	Sierra Pacific Power Company	OS	WSPP	0.000	0.000	0.000
8	Sierra Pacific Power Company	SF	WSPP	0.000	0.000	0.000
9	Snohomish County PUD	OS	WSPP	0.000	0.000	0.000
10	Snohomish County PUD	SF	WSPP	0.000	0.000	0.000
11	TransAlta Energy Marketing (U.S.) I	SF	WSPP	0.000	0.000	0.000
12	Tri-State Generation and Transmissi	SF	WSPP	0.000	0.000	0.000
13	Utah Associated Municipal Power Sys	LF	75	0.000	0.000	0.000
14	Utah Associated Municipal Power Sys	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	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
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Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Washington, UT, City of	LF	74	0.000	0.000	0.000
2	Western Area Power Administration	OS	WSPP	0.000	0.000	0.000
3	Williams Energy Marketing & Trading	SF	WSPP	0.000	0.000	0.000
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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

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

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
54,988	174,307	1,164,923	3,000	1,342,230	1
51,294	365,897	1,025,877	570	1,392,344	2
52,850		1,284,988		1,284,988	3
4,073		99,005		99,005	4
1,600		50,300		50,300	5
300		9,700		9,700	6
10,000		379,500		379,500	7
10,841		394,200		394,200	8
150		2,850		2,850	9
240		7,020		7,020	10
24,934		712,214		712,214	11
780		25,910		25,910	12
20,800		488,800		488,800	13
74,400		2,139,000		2,139,000	14
106,282	540,204	2,190,800	3,570	2,734,574	
1,962,222	7,507,829	44,788,684	0	52,296,513	
2,068,504	**8,048,033**	**46,979,484**	**3,570**	**55,031,087**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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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,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
87,200		2,571,200		2,571,200	1
10,400		338,660		338,660	2
450		10,610		10,610	3
5,400		175,200		175,200	4
35		525		525	5
400		8,000		8,000	6
200		3,900		3,900	7
811,039	2,356,529	16,993,428		19,349,957	8
1	1,371,300	183,986		1,555,286	9
50		2,100		2,100	10
8,200		286,300		286,300	11
43,376		1,597,504		1,597,504	12
6,981		222,795		222,795	13
2,400		70,500		70,500	14
106,282	540,204	2,190,800	3,570	2,734,574	
1,962,222	7,507,829	44,788,684	0	52,296,513	
2,068,504	**8,048,033**	**46,979,484**	**3,570**	**55,031,087**	

SALES FOR RESALE (Account 447) (Continued)

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

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

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
1,267		32,526		32,526	1
9,795		250,185		250,185	2
79,180		1,980,661		1,980,661	3
87,200		2,465,200		2,465,200	4
9,060		226,468		226,468	5
60,150		1,884,863		1,884,863	6
11,767		277,030		277,030	7
22,825		617,888		617,888	8
1,009		32,482		32,482	9
3,830		151,640		151,640	10
999		39,734		39,734	11
1,024		31,600		31,600	12
2,200		75,000		75,000	13
683		15,796		15,796	14
106,282	540,204	2,190,800	3,570	2,734,574	
1,962,222	7,507,829	44,788,684	0	52,296,513	
2,068,504	**8,048,033**	**46,979,484**	**3,570**	**55,031,087**	

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
2,200		66,400		66,400	1
400		14,600		14,600	2
100		2,900		2,900	3
5,076		127,502		127,502	4
20,346		513,885		513,885	5
1,200		49,600		49,600	6
216		4,320		4,320	7
94		1,786		1,786	8
1,605		53,550		53,550	9
800		18,000		18,000	10
7,400		268,810		268,810	11
242		120,122		120,122	12
399,870	3,480,750	6,449,067		9,929,817	13
50		1,499		1,499	14
106,282	540,204	2,190,800	3,570	2,734,574	
1,962,222	7,507,829	44,788,684	0	52,296,513	
2,068,504	**8,048,033**	**46,979,484**	**3,570**	**55,031,087**	

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
28,694	299,250	419,650		718,900	1
290		13,050		13,050	2
25,550		524,675		524,675	3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
106,282	540,204	2,190,800	3,570	2,734,574	
1,962,222	7,507,829	44,788,684	0	52,296,513	
2,068,504	**8,048,033**	**46,979,484**	**3,570**	**55,031,087**	

Name of Respondent	This Report is:	Date of Report	Year of Report
Idaho Power Company	(1) X An Original (2) __ A Resubmission	(Mo, Da, Yr) 04/30/2003	Dec 31, 2002

FOOTNOTE DATA

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

Customer Charge

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

Schedule Page: 310 Line No.: 11 Column: a

Schedule Page: 310.3 Line No.: 13 Column: a

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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	1,013,741	1,050,676
5	(501) Fuel	98,346,451	95,371,284
6	(502) Steam Expenses	3,747,655	5,499,015
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,039,067	1,445,746
10	(506) Miscellaneous Steam Power Expenses	3,810,131	5,520,974
11	(507) Rents	732,669	626,935
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	108,689,714	109,514,630
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	1,855,715	1,871,602
16	(511) Maintenance of Structures	153,018	167,964
17	(512) Maintenance of Boiler Plant	8,450,566	8,734,101
18	(513) Maintenance of Electric Plant	2,808,027	3,464,403
19	(514) Maintenance of Miscellaneous Steam Plant	8,872,260	8,055,570
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	22,139,586	22,293,640
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	130,829,300	131,808,270
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of 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	4,140,933	3,372,540
45	(536) Water for Power	3,027,065	3,208,010
46	(537) Hydraulic Expenses	4,948,636	4,507,941
47	(538) Electric Expenses	944,540	1,279,305
48	(539) Miscellaneous Hydraulic Power Generation Expenses	1,678,676	1,723,166
49	(540) Rents	383,569	303,528
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	15,123,419	14,394,490

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) Mainentance Supervision and Engineering	995,121	1,081,340
54	(542) Maintenance of Structures	1,263,109	1,010,625
55	(543) Maintenance of Reservoirs, Dams, and Waterways	738,221	503,908
56	(544) Maintenance of Electric Plant	2,141,465	2,047,239
57	(545) Maintenance of Miscellaneous Hydraulic Plant	2,223,081	2,131,428
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	7,360,997	6,774,540
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	22,484,416	21,169,030
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	311,907	168,973
63	(547) Fuel	4,524,143	2,947,157
64	(548) Generation Expenses	325,877	503,585
65	(549) Miscellaneous Other Power Generation Expenses	405,666	326,432
66	(550) Rents	18,372	5,138,643
67	TOTAL Operation (Enter Total of lines 62 thru 66)	5,585,965	9,084,790
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	933	55
70	(552) Maintenance of Structures	163,166	14,535
71	(553) Maintenance of Generating and Electric Plant	222,325	260,333
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	351,528	
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	737,952	274,923
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	6,323,917	9,359,713
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	142,102,234	584,209,158
77	(556) System Control and Load Dispatching	11,024	743,677
78	(557) Other Expenses	173,448,997	-174,120,475
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	315,562,255	410,832,360
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	475,199,888	573,169,373
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	1,774,243	1,951,573
84	(561) Load Dispatching	2,416,264	2,380,097
85	(562) Station Expenses	1,837,539	1,247,486
86	(563) Overhead Lines Expenses	568,785	546,695
87	(564) Underground Lines Expenses		
88	(565) Transmission of Electricity by Others	2,213,424	1,521,950
89	(566) Miscellaneous Transmission Expenses	420,442	435,479
90	(567) Rents	1,648,202	1,323,777
91	TOTAL Operation (Enter Total of lines 83 thru 90)	10,878,899	9,407,057
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	774,852	838,863
94	(569) Maintenance of Structures	57,644	262
95	(570) Maintenance of Station Equipment	1,447,053	3,146,988
96	(571) Maintenance of Overhead Lines	2,291,863	2,457,952
97	(572) Maintenance of Underground Lines		
98	(573) Maintenance of Miscellaneous Transmission Plant	9,359	13,399
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	4,580,771	6,457,464
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	15,459,670	15,864,521
101	3. DISTRIBUTION EXPENSES		
102	Operation		
103	(580) Operation Supervision and Engineering	3,363,654	3,382,658

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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	2,354,991	2,625,877
106	(582) Station Expenses	1,373,812	1,346,156
107	(583) Overhead Line Expenses	3,592,457	3,777,453
108	(584) Underground Line Expenses	2,353,356	2,542,445
109	(585) Street Lighting and Signal System Expenses	371,306	373,290
110	(586) Meter Expenses	6,075,032	4,724,574
111	(587) Customer Installations Expenses	491,519	525,628
112	(588) Miscellaneous Expenses	3,660,582	3,714,463
113	(589) Rents	169,860	166,530
114	TOTAL Operation (Enter Total of lines 103 thru 113)	23,806,569	23,179,074
115	Maintenance		
116	(590) Maintenance Supervision and Engineering	64,762	89,333
117	(591) Maintenance of Structures	6,000	2,162
118	(592) Maintenance of Station Equipment	2,636,012	2,781,089
119	(593) Maintenance of Overhead Lines	10,914,719	10,872,200
120	(594) Maintenance of Underground Lines	1,180,556	1,383,311
121	(595) Maintenance of Line Transformers	1,408,730	1,669,217
122	(596) Maintenance of Street Lighting and Signal Systems	273,422	66,535
123	(597) Maintenance of Meters	1,491,396	1,734,298
124	(598) Maintenance of Miscellaneous Distribution Plant	161,683	208,850
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	18,137,280	18,806,995
126	TOTAL Distribution Exp (Enter Total of lines 114 and 125)	41,943,849	41,986,069
127	4. CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision	412,133	612,115
130	(902) Meter Reading Expenses	4,367,046	4,293,139
131	(903) Customer Records and Collection Expenses	6,873,881	8,932,866
132	(904) Uncollectible Accounts	4,765,303	3,606,470
133	(905) Miscellaneous Customer Accounts Expenses	2,266	2,341
134	TOTAL Customer Accounts Expenses (Total of lines 129 thru 133)	16,420,629	17,446,931
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision	265,513	160,783
138	(908) Customer Assistance Expenses	7,838,129	8,275,752
139	(909) Informational and Instructional Expenses	25	18,251
140	(910) Miscellaneous Customer Service and Informational Expenses	487,125	295,187
141	TOTAL Cust. Service and Information. Exp. (Total lines 137 thru 140)	8,590,792	8,749,973
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	29,332,171	33,743,434
152	(921) Office Supplies and Expenses	17,149,539	15,501,063
153	(Less) (922) Administrative Expenses Transferred-Credit	18,948,998	18,801,480

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	4,581,162	5,047,875
156	(924) Property Insurance	2,862,999	2,239,668
157	(925) Injuries and Damages	2,764,991	2,954,301
158	(926) Employee Pensions and Benefits	18,547,555	10,589,654
159	(927) Franchise Requirements	1,750	1,575
160	(928) Regulatory Commission Expenses	3,473,789	3,515,247
161	(929) (Less) Duplicate Charges-Cr.		
162	(930.1) General Advertising Expenses	578,126	836,839
163	(930.2) Miscellaneous General Expenses	1,316,830	1,411,712
164	(931) Rents	28,169	32,292
165	TOTAL Operation (Enter Total of lines 151 thru 164)	61,688,083	57,072,180
166	Maintenance		
167	(935) Maintenance of General Plant	1,642,670	1,269,016
168	TOTAL Admin & General Expenses (Total of lines 165 thru 167)	63,330,753	58,341,196
169	TOTAL Elec Op and Maint Expn (Tot 80, 100, 126, 134, 141, 148, 168)	620,945,581	715,558,063

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Cogeneration and Small Power Producers					
2	Willis and Betty Deveny	LU	-	N/A	N/A	N/A
3	James B Howell	LU	-	N/A	N/A	N/A
4	Tamarack Energy Partnership	LU	-	4.942Mw	N/A	N/A
5	Owyhee Irrigation District					
6	Mitchell Butte	LU	-	N/A	N/A	N/A
7	Owyhee Dam	LU	-	N/A	N/A	N/A
8	Tunnel #1	LU	-	N/A	N/A	N/A
9	Reynolds Irrigation District	LU	-	N/A	N/A	N/A
10	Clifton E. Jenson	LU	-	.05Mw	N/A	N/A
11	Snake River Pottery	LU	-	N/A	N/A	N/A
12	White Water Ranch	LU	-	N/A	N/A	N/A
13	John R LeMoyne	LU	-	N/A	N/A	N/A
14	David R Snedigar	LU	-	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Box Canyon	LU	-	N/A	N/A	N/A
2	Briggs Creek	LU	-	N/A	N/A	N/A
3	J D McCollum	LU	-	N/A	N/A	N/A
4	Zions Credit Corp / Mud Creek S	LU	-	N/A	N/A	N/A
5	Vernon Ravenscroft	LU	-	.488Mw	N/A	N/A
6	William Arkoosh	LU	-	N/A	N/A	N/A
7	Clear Springs Food Inc.	LU	-	N/A	N/A	N/A
8	Koyle Hydro Inc.	LU	-	N/A	N/A	N/A
9	Kasel & Witherspoon	LU	-	N/A	N/A	N/A
10	Lateral 10 Ventures	LU	-	N/A	N/A	N/A
11	Crystal Springs Hydro	LU	-	N/A	N/A	N/A
12	Pigeon Cove Power	LU	-	1.389	N/A	N/A
13	Notch Butte Hydro Co Inc.	LU	-	N/A	N/A	N/A
14	Consolidated Hydro Inc.					
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Barber Dam	LU	-	N/A	N/A	N/A
2	Rock Creek II	LU	-	N/A	N/A	N/A
3	Dietrich Drop	LU	-	N/A	N/A	N/A
4	Lowline #2	LU	-	N/A	N/A	N/A
5	Cedar Draw/ Little Mac Power	LU	-	N/A	N/A	N/A
6	South Forks Joint Venture	LU	-	N/A	N/A	N/A
7	Little Wood River Irrigation Dis	LU	-	N/A	N/A	N/A
8	Rancher's Irrigation District	LU	-	N/A	N/A	N/A
9	Faulkner Brothers Hydro Inc.	LU	-	N/A	N/A	N/A
10	Magic Reservoir Hydro	LU	-	N/A	N/A	N/A
11	Bypass Limited	LU	-	N/A	N/A	N/A
12	SE Hazelton A LP	LU	-	N/A	N/A	N/A
13	Jerry L McMillan	OS	-	N/A	N/A	N/A
14	Lemhi HydroPower Company	LU	-	N/A	N/A	N/A
	Total					

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1	J R Simplot	LU	-	N/A	N/A	N/A
2	Blind Canyon Hydro	LU	-	N/A	N/A	N/A
3	City of Boise	LU	-	N/A	N/A	N/A
4	City of Hailey	LU	-	N/A	N/A	N/A
5	City of Pocatello	LU	-	N/A	N/A	N/A
6	Marysville Hydro Partners	LU	-	N/A	N/A	N/A
7	Wilson Power Company	LU	-	N/A	N/A	N/A
8	Hazelton Power Company	LU	-	N/A	N/A	N/A
9	Pristine Springs	LU	-	N/A	N/A	N/A
10	Vaagen Brothers Lumber Inc.	LU	-	N/A	N/A	N/A
11	Horseshoe Bend Hydro	LU	-	N/A	N/A	N/A
12	Contractors Power Group Inc.	LU	-	N/A	N/A	N/A
13	Rupert Cogeneration Partners	LU	-	N/A	N/A	N/A
14	Glenns Ferry Cogeneration Partne	LU	-	N/A	N/A	N/A
	Total					

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1	Lewandowski Farms	OS	-	N/A	N/A	N/A
2	Tasco - Nampa	OS	-	N/A	N/A	N/A
3	Tasco - Twin Falls	OS	-	N/A	N/A	N/A
4	Energy Differences					
5						
6	Other Purchased Power					
7	AEP Service Corp.	OS	WSPP	N/A	N/A	N/A
8	AEP Service Corp.	SF	WSPP	N/A	N/A	N/A
9	Avista Corp. - WWP Div.	OS	WSPP	N/A	N/A	N/A
10	Avista Corp. - WWP Div.	SF	WSPP	N/A	N/A	N/A
11	Avista Energy, Inc.	OS	WSPP	N/A	N/A	N/A
12	Avista Energy, Inc.	SF	WSPP	N/A	N/A	N/A
13	Benton County PUD	OS	WSPP	N/A	N/A	N/A
14	Benton County PUD	SF	WSPP	N/A	N/A	N/A
	Total					

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1	Bonneville Power Administration	OS	WSPP	N/A	N/A	N/A
2	Bonneville Power Administration	SF	WSPP	N/A	N/A	N/A
3	BP Energy Company	SF	WSPP	N/A	N/A	N/A
4	Cargill-Alliant, LLC	OS	WSPP	N/A	N/A	N/A
5	Chelan Co PUD	OS	WSPP	N/A	N/A	N/A
6	Chelan Co PUD	SF	WSPP	N/A	N/A	N/A
7	Clatskanie PUD	SF		N/A	N/A	N/A
8	Constellation Power Source, Inc.	OS	WSPP	N/A	N/A	N/A
9	Douglas County PUD	OS	WSPP	N/A	N/A	N/A
10	Dynegy Power Marketing, Inc.	SF	WSPP	N/A	N/A	N/A
11	El Paso Electric Company	OS	WSPP	N/A	N/A	N/A
12	El Paso Electric Company	SF	WSPP	N/A	N/A	N/A
13	El Paso Merchant Energy, L.P.	SF	WSPP	N/A	N/A	N/A
14	Enron Power Marketing	SF	WSPP	N/A	N/A	N/A
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/2003	Year of Report Dec. 31, 2002

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1	Enron Power Marketing	SF	WSPP	N/A	N/A	N/A
2	Entergy-Koch Trading, LP	SF	WSPP	N/A	N/A	N/A
3	Eugene Water & Electric Board	OS	WSPP	N/A	N/A	N/A
4	Franklin County P.U.D.	OS	WSPP	N/A	N/A	N/A
5	Franklin County P.U.D.	SF	WSPP	N/A	N/A	N/A
6	Grant County P.U.D.	OS	WSPP	N/A	N/A	N/A
7	Grant County P.U.D.	SF	WSPP	N/A	N/A	N/A
8	Grays Harbor PUD	OS	WSPP	N/A	N/A	N/A
9	Grays Harbor PUD	SF	WSPP	N/A	N/A	N/A
10	IDACORP Energy L.P.	SF	V6-48	N/A	N/A	N/A
11	IDACORP Energy L.P.	SF	V6-48	N/A	N/A	N/A
12	Mieco, Inc.	SF	WSPP	N/A	N/A	N/A
13	Morgan Stanley Capital Group Inc	SF	WSPP	N/A	N/A	N/A
14	Nevada Power Company	OS	WSPP	N/A	N/A	N/A
	Total					

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	NorthPoint Energy Solutions Inc.	OS	WSPP	N/A	N/A	N/A
2	NorthWestern Energy, L.L.C.	OS	WSPP	N/A	N/A	N/A
3	NorthWestern Energy, L.L.C.	SF	WSPP	N/A	N/A	N/A
4	PacifiCorp Inc.	OS	WSPP	N/A	N/A	N/A
5	PacifiCorp Inc.	SF	WSPP	N/A	N/A	N/A
6	PacifiCorp Power Marketing, Inc.	OS	WSPP	N/A	N/A	N/A
7	PacifiCorp Power Marketing, Inc.	SF	WSPP	N/A	N/A	N/A
8	PG&E Energy Trading - Power LP	SF	WSPP	N/A	N/A	N/A
9	Pinnacle West Capital Corporatio	OS	WSPP	N/A	N/A	N/A
10	Pinnacle West Capital Corporatio	SF	WSPP	N/A	N/A	N/A
11	Portland General Electric Compan	OS	WSPP	N/A	N/A	N/A
12	Portland General Electric Compan	SF	WSPP	N/A	N/A	N/A
13	Portland General Electric Compan	SF		N/A	N/A	N/A
14	Powerex Corp.	OS	WSPP	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Powerex Corp.	SF	WSPP	N/A	N/A	N/A
2	PPL Montana, LLC	OS	WSPP	N/A	N/A	N/A
3	PPL Montana, LLC	SF	WSPP	N/A	N/A	N/A
4	Public Service Co. of Colorado	OS	WSPP	N/A	N/A	N/A
5	Public Service Company of New Me	OS	WSPP	N/A	N/A	N/A
6	Public Service Company of New Me	SF	WSPP	N/A	N/A	N/A
7	Puget Sound Energy, Inc.	OS	WSPP	N/A	N/A	N/A
8	Puget Sound Energy, Inc.	SF	WSPP	N/A	N/A	N/A
9	Rocky Mountain Generation	OS	WSPP	N/A	N/A	N/A
10	Salt River Project	OS	WSPP	N/A	N/A	N/A
11	Seattle City Light	OS	WSPP	N/A	N/A	N/A
12	Seattle City Light	SF	WSPP	N/A	N/A	N/A
13	Sierra Pacific Power Company	OS	WSPP	N/A	N/A	N/A
14	Sierra Pacific Power Company	SF	WSPP	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Snohomish County PUD	OS	WSPP	N/A	N/A	N/A
2	Snohomish County PUD	SF	WSPP	N/A	N/A	N/A
3	Tacoma Power	OS	WSPP	N/A	N/A	N/A
4	Tacoma Power	SF	WSPP	N/A	N/A	N/A
5	Tractebel Energy Marketing, Inc.	SF	WSPP	N/A	N/A	N/A
6	TransAlta Energy Marketing (U.S.	OS	WSPP	N/A	N/A	N/A
7	TransAlta Energy Marketing (U.S.	SF	WSPP	N/A	N/A	N/A
8	Tri-State Generation and Transmi	OS	WSPP	N/A	N/A	N/A
9	Tri-State Generation and Transmi	SF	WSPP	N/A	N/A	N/A
10	Turlock Irrigation District	OS	WSPP	N/A	N/A	N/A
11	Turlock Irrigation District	SF	WSPP	N/A	N/A	N/A
12	Utah Associated Municipal Power	OS	WSPP	N/A	N/A	N/A
13	Utah Associated Municipal Power	SF	WSPP	N/A	N/A	N/A
14	Western Area Power Administratio	OS	WSPP	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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.

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Western Area Power Administratio	OS	WSPP	N/A	N/A	N/A
2	Voluntary Irrigation Load Reduct	OS	-	N/A	N/A	N/A
3	Astaris, LLC	OS	-	N/A	N/A	N/A
4	Insurance Recovery	OS	-	N/A	N/A	N/A
5						
6	Power Exchanges					
7	City of Seattle	EX	71			
8	PPL Montana, LLC	EX	70			
9	Bonneville Power Adm	EX	WSPP			
10	Sierra Pacific Power Company	EX	WSPP			
11	Bonneville Power Administration	EX	-			
12	Montana Power Co.	EX	-			
13	NorthWestern Energy, L.L.C.	EX	-			
14	PacifiCorp Inc.	EX	-			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Seattle City Light	EX	-			
2	Sierra Pacific Power Company	EX	-			
3	Other Transactions					
4	Acctg Valuation of City					
5	of Seattle Exchange					
6	Acctg Valuation of Sierra					
7	Pacific Power Co Exchange					
8						
9						
10						
11						
12						
13						
14						
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
							1
748				49,077		49,077	2
3,886				251,766		251,766	3
41,638			1,576,498	1,401,787		2,978,285	4
							5
5,611				412,226		412,226	6
17,348				1,120,878		1,120,878	7
7,539				685,905		685,905	8
1,496				105,296		105,296	9
291			17,500	7,184		24,684	10
402				25,094		25,094	11
682				42,312		42,312	12
644				34,639		34,639	13
1,444				92,609		92,609	14
2,855,620	477,026	496,849	2,812,891	137,796,388	1,492,955	142,102,234	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
376				22,803		22,803	1
1,578				24,950		24,950	2
639			24,563	15,738		40,301	3
913				59,753		59,753	4
							5
295				19,149		19,149	6
777				50,801		50,801	7
976				65,107		65,107	8
809				13,752		13,752	9
							10
1,615				121,975		121,975	11
1,861				119,731		119,731	12
10,225			552,508	252,034		804,542	13
							14
2,855,620	477,026	496,849	2,812,891	137,796,388	1,492,955	142,102,234	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
1,627				100,311		100,311	1
3,804				238,240		238,240	2
812				55,440		55,440	3
1,276				87,763		87,763	4
1,215			155,672	29,950		185,622	5
2,962				208,161		208,161	6
3,636				293,260		293,260	7
3,186				248,307		248,307	8
3,496				255,563		255,563	9
6,110				371,201		371,201	10
7,026				432,997		432,997	11
7,654			486,150	164,023		650,173	12
2,634				187,042		187,042	13
							14
2,855,620	477,026	496,849	2,812,891	137,796,388	1,492,955	142,102,234	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
10,303				479,570		479,570	1
5,287				245,505		245,505	2
13,187				662,244		662,244	3
8,952				436,757		436,757	4
5,114				307,804		307,804	5
25,032				1,701,112		1,701,112	6
3,031				218,450		218,450	7
2,083				131,072		131,072	8
2,302				166,080		166,080	9
4,031				171,355		171,355	10
23,379				1,146,578		1,146,578	11
20,298				946,597		946,597	12
146				2,301		2,301	13
1,010				72,119		72,119	14
2,855,620	477,026	496,849	2,812,891	137,796,388	1,492,955	142,102,234	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
89,881				7,051,149		7,051,149	1
3,340				209,280		209,280	2
1,040				62,820		62,820	3
132				8,832		8,832	4
1,490				101,158		101,158	5
38,076				2,267,711		2,267,711	6
23,138				1,506,888		1,506,888	7
20,462				1,330,998		1,330,998	8
930				38,861		38,861	9
27,261				1,163,634		1,163,634	10
38,943				2,555,701		2,555,701	11
3,738				244,513		244,513	12
85,093				5,079,131		5,079,131	13
85,835				5,126,374		5,126,374	14
2,855,620	477,026	496,849	2,812,891	137,796,388	1,492,955	142,102,234	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
21				550		550	1
1,648				16,802		16,802	2
							3
7							4
							5
							6
25				750		750	7
74,271				2,135,291		2,135,291	8
11,073				232,222		232,222	9
5,800				83,815		83,815	10
7,795				232,062		232,062	11
2,113				59,535		59,535	12
2,491				59,398		59,398	13
3,400				54,880		54,880	14
2,855,620	477,026	496,849	2,812,891	137,796,388	1,492,955	142,102,234	

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
29,651				684,766		684,766	1
184,145				4,783,582		4,783,582	2
1,200				19,320		19,320	3
200				5,150		5,150	4
165				3,465		3,465	5
3,200				69,850		69,850	6
1,600				40,800		40,800	7
300				12,600		12,600	8
320				3,520		3,520	9
9,600				213,600		213,600	10
175				4,000		4,000	11
420				2,100		2,100	12
64,600				1,575,800		1,575,800	13
74,400				2,362,200		2,362,200	14
2,855,620	477,026	496,849	2,812,891	137,796,388	1,492,955	142,102,234	

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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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)	
87,200				3,571,600		3,571,600	1
11,400				303,330		303,330	2
80				1,120		1,120	3
1,190				30,985		30,985	4
880				14,280		14,280	5
3,077				95,260		95,260	6
18,000				409,500		409,500	7
1,555				43,060		43,060	8
3,960				62,930		62,930	9
1,028,524				17,107,571		17,107,571	10
-1				-4,038,775		-4,038,775	11
800				18,340		18,340	12
177,224				5,283,924		5,283,924	13
600				11,450		11,450	14
2,855,620	477,026	496,849	2,812,891	137,796,388	1,492,955	142,102,234	

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
300				5,400		5,400	1
9,150				193,436		193,436	2
10,375				377,853		377,853	3
18,602				542,696		542,696	4
5,711				191,749		191,749	5
2,186				54,058		54,058	6
124				1,596		1,596	7
2,000				34,300		34,300	8
900				17,550		17,550	9
53,550				1,946,061		1,946,061	10
5,678				183,421		183,421	11
49,045				1,685,835		1,685,835	12
1,000				14,728		14,728	13
5,109				187,078		187,078	14
2,855,620	477,026	496,849	2,812,891	137,796,388	1,492,955	142,102,234	

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MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
2,250				80,700		80,700	1
21,629				602,426		602,426	2
49,678				1,495,873		1,495,873	3
675				13,137		13,137	4
675				19,325		19,325	5
9				315		315	6
9,875				251,519		251,519	7
16,463				411,637		411,637	8
5,751				92,214		92,214	9
1,375				26,755		26,755	10
1,035				25,820		25,820	11
800				14,400		14,400	12
231				5,613		5,613	13
3,302				54,478		54,478	14
2,855,620	477,026	496,849	2,812,891	137,796,388	1,492,955	142,102,234	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
4,420				116,015		116,015	1
200				6,300		6,300	2
2,975				77,200		77,200	3
425				7,575		7,575	4
10,000				362,500		362,500	5
8,752				242,706		242,706	6
10,500				218,925		218,925	7
1,350				26,330		26,330	8
120				2,460		2,460	9
245				3,435		3,435	10
3,495				56,978		56,978	11
19,646				413,422		413,422	12
4,809				130,844		130,844	13
1,265				16,070		16,070	14
2,855,620	477,026	496,849	2,812,891	137,796,388	1,492,955	142,102,234	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
6,086				123,118		123,118	1
				3,184		3,184	2
				50,787,302		50,787,302	3
					15,735	15,735	4
							5
							6
	126,000	70,800					7
	118,800	108,000					8
	68,400	71,900					9
	26,824	26,824					10
	66,970	7,939					11
		135					12
		6					13
	69,565	199,035					14
2,855,620	477,026	496,849	2,812,891	137,796,388	1,492,955	142,102,234	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
	467						1
		12,210					2
							3
							4
					1,474,184	1,474,184	5
							6
					3,036	3,036	7
							8
							9
							10
							11
							12
							13
							14
2,855,620	477,026	496,849	2,812,891	137,796,388	1,492,955	142,102,234	

FOOTNOTE DATA

Schedule Page: 326 Line No.: 4 Column: a

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Schedule Page: 326.3 Line No.: 6 Column: a

Schedule Page: 326.3 Line No.: 13 Column: b

Schedule Page: 326.4 Line No.: 6 Column: a

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Schedule Page: 326.5 Line No.: 1 Column: b

Schedule Page: 326.5 Line No.: 2 Column: b

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Schedule Page: 326.7 Line No.: 1 Column: a

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Schedule Page: 326.8 Line No.: 13 Column: a

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

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

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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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, municipalities, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers.
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:
LF - for Long-term firm transmission service. "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 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.
SF - for short-term firm transmission service. Use this category for all firm services, where the duration of each period of commitment for service is less than one year.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Bonneville Power Administration	Bonneville Power Administration	Oregon Trails Electric Co-op	LF
2	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	LF
3	Bonneville Power Administration	Bonneville Power Administration	Vigilante	LF
4	Milner Irrigation District	Bureau of Reclamation	Milner Irrigation District	LF
5	City of Seattle	City of Seattle	Bonneville Power Administration	LF
6	United States Bureau of Indian Affairs	Bonneville Power Administration	United States Bureau of Indian Af	LF
7	Aquilla Power Corporation	Aquilla Power Corporation	PacifiCorp	OS
8	Arizona Public Service/Pinnacle West	Arizona Public Service/Pinnacle W	Bonneville Power Administration	LF
9	Arizona Public Service/Pinnacle West	Arizona Public Service/Pinnacle W	Northwestern	LF
10	Arizona Public Service/Pinnacle West	Arizona Public Service/Pinnacle W	Bonneville Power Administration	OS
11	BC Hydro (Powerx)	BC Hydro (Powerx)	Nevada Power Company/Sierra Pacif	OS
12	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	OS
13	City of Idaho Falls	Bonneville Power Administration	Northwestern	OS
14	City of Seattle	City of Seattle	Bonneville Power Administration	AD
15	Conoco	Bonneville Power Administration	Northwestern	OS
16	IdaCorp Energy	Idaho Power Company	Various	OS
17	Mirant Americas Energy Marketing, LP	Mirant Americas Energy Marketing,	PacifiCorp	OS
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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, municipalities, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers.
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:
LF - for Long-term firm transmission service. "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 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.
SF - for short-term firm transmission service. Use this category for all firm services, where the duration of each period of commitment for service is less than one year.

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	Montana Power Company	Montana Power Company	PacifiCorp - East	OS
2	Morgan Stanley Capital Group, Inc.	Morgan Stanley Capital Group, Inc	Nevada Power Company/Sierra Pacif	OS
3	Nevada Power Company/Sierra Pacific Powe	Nevada Power Company/Sierra Pacif	Nevada Power Company/Sierra Pacif	OS
4	PacifiCorp	PacifiCorp	PacifiCorp - East	OS
5	PacifiCorp	PacifiCorp	PacifiCorp	OS
6	PacifiCorp - Imnaha	PacifiCorp	PacifiCorp	LF
7	Public Service Colorado	Public Service Colorado	Bonneville Power Administration	OS
8	Puget Sound Power & Light	Puget Sound Power & Light	Bonneville Power Administration	OS
9	Transalta Energy	PacifiCorp	PacifiCorp - East	OS
10	TXU	Northwestern	PacifiCorp - East	OS
11	El Paso	El Paso	El Paso	AD
12				
13				
14				
15				
16				
17				
	TOTAL			

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

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all nonfirm 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.

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.

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.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
Legacy	LaGrande, Oregon	Various in Oregon	714	260,702	260,702	1
Legacy	LaGrande, Oregon	Various in Idaho	2,058	1,088,502	1,088,502	2
5	Bannack Tap	Vigilante Electric C	4			3
Legacy	Minidoka, Idaho	Various in Idaho		8,472	8,472	4
Legacy	Lucky Peak, Idaho	LaGrande, Oregon	591	11,227	9,355	5
Legacy	LaGrande, Oregon	Various in Idaho	11	16,150	16,150	6
5	Enterprise, Oregon	Borah or Brady, Idah		100	100	7
5	Borah or Kinport, Id	LaGrande, Oregon		231,869	231,869	8
5	Borah or Kinport, Id	Lolo, Montana		77,290	77,290	9
5	Various in Idaho	Varrious in Idaho		92,757	92,757	10
5	Various in Idaho	Midpoint, Idaho		79,178	79,178	11
5	Various in Idaho	Various in Idaho		3,147	3,147	12
5	LaGrande, Oregon	Borah or Brady, Idah		17,698	17,698	13
5	Various in Idaho	LaGrande, Oregon				14
5	LaGrande, Oregon	Borah or Brady, Idah		5	5	15
5	Various in Idaho	Various in Idaho		663,510	663,510	16
5	Various in Idaho	Jim Bridger, Wyoming		115	115	17
			3,378	**4,712,790**	**4,710,918**	

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

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all nonfirm 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.
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.
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.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
5	Various in Idaho	Borah or Brady, Idah		17,241	17,241	1
5	Various in Idaho	Humbolt, Nevada		286,611	286,611	2
5	Various in Idaho	Humbolt, Nevada		1,254,577	1,254,577	3
Legacy	Jim Bridger, Wyoming	Various in Idaho		512,283	512,283	4
5	Enterprise, Oregon	Various in Idaho		84,839	84,839	5
5	Enterprise, Oregon	Pine Creek, Oregon		2,289	2,289	6
5	Borah or Kinport, Id	Lolo, Montana		385	385	7
5	Hot Spings	Lolo, Montana		100	100	8
5	Enterprise, Oregon	Borah or Brady, Idah		3,718	3,718	9
5	Lolo, Montana	Borah or Brady, Idah		25	25	10
5	Various in Idaho	Various in Idaho				11
						12
						13
						14
						15
						16
						17
			3,378	**4,712,790**	**4,710,918**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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

8. Report in column (i) and (j) the total megawatthours received and delivered.
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 (I), 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. Provide total amounts in column (i) through (n) as the last Line. Enter "TOTAL" in column (a) as the Last Line. The total amounts in columns (i) and (j) must be reported as Transmission Received and Delivered 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.
1,285,366			1,285,366	1
2,942,300	822,957	228,156	3,993,413	2
15,000			15,000	3
	13,725		13,725	4
845,130		4,860	849,990	5
53,653			53,653	6
	359		359	7
	1,093,724		1,093,724	8
	364,575		364,575	9
	437,537		437,537	10
	314,242		314,242	11
	10,033		10,033	12
	37,623		37,623	13
		-4,553	-4,553	14
	20		20	15
	2,356,783		2,356,783	16
	429		429	17
5,141,449	**11,023,039**	**228,453**	**16,392,941**	

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

8. Report in column (i) and (j) the total megawatthours received and delivered.
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. Provide total amounts in column (i) through (n) as the last Line. Enter "TOTAL" in column (a) as the Last Line. The total amounts in columns (i) and (j) must be reported as Transmission Received and Delivered on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	62,398		62,398	1
	789,399		789,399	2
	3,444,311		3,444,311	3
	802,112		802,112	4
	442,006		442,006	5
	14,580		14,580	6
	283		283	7
	1,478		1,478	8
	14,342		14,342	9
	123		123	10
		-10	-10	11
				12
				13
				14
				15
				16
				17
5,141,449	**11,023,039**	**228,453**	**16,392,941**	

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

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

Schedule Page: 328 Line No.: 2 Column: a

Schedule Page: 328 Line No.: 2 Column: m

Schedule Page: 328 Line No.: 3 Column: a

Schedule Page: 328 Line No.: 3 Column: e

Schedule Page: 328 Line No.: 4 Column: a

Schedule Page: 328 Line No.: 5 Column: a

Schedule Page: 328 Line No.: 5 Column: m

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

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

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

Schedule Page: 328 Line No.: 14 Column: m

Schedule Page: 328.1 Line No.: 4 Column: a

Schedule Page: 328.1 Line No.: 11 Column: m

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/2003	Year of Report Dec. 31, 2002

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

1. Report all transmission, i.e., wheeling of electricity provided to respondent by other electric utilities, cooperatives, municipalities, or other public authorities during the year.
2. In column (a) report each company or public authority that provide 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.
3. Provide in column (a) subheadings and classify transmission service purchased form other utilities as: "Delivered Power to Wheeler" or "Received Power from Wheeler."
4. Report in columns (b) and (c) the total Megawatthours received and delivered by the provider of the transmission service.
5. In columns (d) through (g), report expenses as shown on bills or vouchers rendered to the respondent. In column (d), provide demand charges. In column (e), provide energy charges related to the amount of energy transferred. In column (f), provide 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 (f). Report in column (9) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero ("0") column (g). 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. Provide a total amount in columns (b) through (g) as the last Line. Energy provided by the respondent for the wheeler's transmission tosses should be reported on the Electric Energy Account, Page 401. If the respondent received power from the wheeler, energy provided to account for Losses should be reported on Line 19. Transmission By Others Losses, on Page 401. Otherwise, Losses should be reported on line 27, Total Energy Losses, Page 401.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	TRANSFER OF ENERGY Magawatt-hours Received (b)	Magawatt-hours Delivered (c)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (d)	Energy Charges ($) (e)	Other Charges ($) (f)	Total Cost of Transmission ($) (g)
1	Delivered Power to						
2	Benton County PUD	5,672	5,672		10,006		10,006
3	Bonneville Power Admin	504,934	504,934	41,724	1,776		43,500
4	Clatskanie PUD	200	200		350		350
5	Franklin County PUD	160	160		280		280
6	Grays Harbor PUD	18,910	18,910		3,230		3,230
7	IdaCorp Energy				611,834		611,834
8	Northwest Energy	128	128		596		596
9	PacifiCorp Inc	1,569	1,569		9,582		9,582
10	Seattle City Light	3,300	3,300		6,155		6,155
11	Sierra Pacific Power Co	108	108		748		748
12	Snohomish County PUD	259	259		583		583
13							
14	Rec'd Power from						
15	Avista Corp	17,035	17,035		49,980		49,980
16	Benton County PUD	4,120	4,120		7,500		7,500
	TOTAL	1,375,448	1,375,448	1,158,852	1,054,572		2,213,424

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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

1. Report all transmission, i.e., wheeling of electricity provided to respondent by other electric utilities, cooperatives, municipalities, or other public authorities during the year.
2. In column (a) report each company or public authority that provide 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.
3. Provide in column (a) subheadings and classify transmission service purchased form other utilities as: "Delivered Power to Wheeler" or "Received Power from Wheeler."
4. Report in columns (b) and (c) the total Megawatthours received and delivered by the provider of the transmission service.
5. In columns (d) through (g), report expenses as shown on bills or vouchers rendered to the respondent. In column (d), provide demand charges. In column (e), provide energy charges related to the amount of energy transferred. In column (f), provide 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 (f). Report in column (9) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero ("0") column (g). 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. Provide a total amount in columns (b) through (g) as the last Line. Energy provided by the respondent for the wheeler's transmission tosses should be reported on the Electric Energy Account, Page 401. If the respondent received power from the wheeler, energy provided to account for Losses should be reported on Line 19. Transmission By Others Losses, on Page 401. Otherwise, Losses should be reported on line 27, Total Energy Losses, Page 401.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
	(a)	Magawatt-hours Received (b)	Magawatt-hours Delivered (c)	Demand Charges ($) (d)	Energy Charges ($) (e)	Other Charges ($) (f)	Total Cost of Transmission ($) (g)
1	Bonneville Power Admin	639,360	639,360	913,128	376		913,504
2	Grant County PUD	3,640	3,640		7,080		7,080
3	Northwestern Energy	105,236	105,236	204,000	13,681		217,681
4	PacifiCorp Inc	60,600	60,600		310,824		310,824
5	Seattle City Light	8,732	8,732		16,650		16,650
6	Snohomish County PUD	1,485	1,485		3,341		3,341
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
	TOTAL	1,375,448	1,375,448	1,158,852	1,054,572		2,213,424

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	18,154
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	1,014,929
6	Rotheford Barker	18,020
7	John Carley	18,040
8	Jack Lemley	19,540
9	Gary Michael	18,690
10	Peter O'Neil	17,520
11	Robert Tinstman	19,540
12	Evelyn Loveless	18,020
13	Christopher Culp	15,515
14	Roger Breezley (1)	7,760
15	Jon Miller	36,000
16		
17		
18		
19	Miscellaneous General Management	
20	Listing Services-New York Stock Exchange	35,000
21	Pacific Stock Exchange	1,000
22		
23	Memberships:	
24	Assessors Convention	50
25	Associated Taxpayers of Idaho	21,939
26	Idaho Cattlemen Assoc	100
27	Idaho Mining Assoc	2,500
28	Idaho Water Users Assoc.,Inc	1,200
29	Idaho Wool Growers	100
30	Ntl. Assoc. of Investors Corp	125
31	Oregonians for Food and Shelter	1,000
32	Pacific NW Utilities	28,704
33	Western Coal Transportation	1,000
34	Wyoming Taxpayers Association	2,384
35		
36		
37		
38		
39		
40	(1) Reiteired 8/2002	
41		
42		
43		
44		
45		
46	TOTAL	1,316,830

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)

(Except amortization of aquisition adjustments)

1. Report in Section A for the year the amounts for: (a) Depreciation Expense (Account 403); (b) Amortization of Limited-Term Electric Plant (Account 404); and (c) 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)	Amortization of Limited Term Electric Plant (Acc 404) (c)	Amortization of Other Electric Plant (Acc 405) (d)	Total (e)
1	Intangible Plant		8,519,346		8,519,346
2	Steam Production Plant	23,350,222			23,350,222
3	Nuclear Production Plant				
4	Hydraulic Production Plant-Conventional	12,064,719	312		12,065,031
5	Hydraulic Production Plant-Pumped Storage				
6	Other Production Plant	1,588,354			1,588,354
7	Transmission Plant	10,830,656			10,830,656
8	Distribution Plant	28,957,208			28,957,208
9	General Plant	8,402,156			8,402,156
10	Common Plant-Electric				
11	TOTAL	85,193,315	8,519,658		93,712,973

B. Basis for Amortization Charges

Account 404

	Balance to be Amortized	2002 Amortization	Balance to be amortized 12/31/02	Remaining months of amortization 12/31/02
(1)	61,540	15,372	46,168	43
(2)	12,000	12,000	60,000	60
(3)	6,907,568	206,712	581,127	-
(4)	34,455,335	8,273,322	24,087,463	-
(5)	283,838	12,252	261,357	266
Total		8,519,658		

(1) T E Roach development archaeological study, FERC & Oregon license costs (temination 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).
(5) American Falls dam road rebuild (termination date February 28, 2025).

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	196	45.00		2.20	Life Span	30.00
13	311.00	129,006	39.00	-17.00	2.97	Life Span	28.30
14	312.10	78,150	41.00	-21.00	3.51	Life Span	28.90
15	312.20	365,659	39.00	-17.00	2.99	Life Span	27.90
16	312.30	4,045	25.00	5.00	3.91	Life Span	24.10
17	314.00	110,042	39.00	-18.00	3.24	Life Span	28.50
18	315.00	61,027	39.00	-16.00	3.01	Life Span	27.90
19	316.00	10,378	39.00	-16.00	4.16	Life Span	23.40
20	316.40	238	7.00	25.00	11.03	R2.5	4.20
21	316.50	17	7.00	15.00	12.53	R2.5	4.70
22	316.70	22	14.00	30.00	5.05	R0.5	11.40
23	316.80	1,133	20.00	40.00	3.05	R1.0	14.30
24	Subtotal Steam	759,913					
25	331.00	127,165	75.00	-19.00	1.88	Life Span	45.60
26	332.10	19,460	80.00		1.56	Life Span	44.00
27	332.20	217,630	76.00	-29.00	2.49	Life Span	41.50
28	332.30	5,600	39.00		2.61	Life Span	38.70
29	333.00	182,144	74.00		1.55	Life Span	45.60
30	334.00	35,374	74.00	-10.00	1.92	Life Span	40.60
31	335.00	13,894	75.00	-5.00	1.59	life Span	46.50
32	336.00	6,934	77.00		1.53	Life Span	45.30
33	Subtotal Hydro	608,201					
34	341.00	1,206	30.00		2.74	Life Span	30.00
35	342.00	1,675	30.00		3.52	Life Span	30.00
36	343.00	765	30.00		3.32	Life Span	30.00
37	344.00	42,883	30.00		3.24	Life Span	30.00
38	345.00	1,237	30.00		3.22	Life Span	30.00
39	346.00	2,479	30.00		3.31	Life Span	30.00
40	Subtotal Other	50,245					
41	350.00	15,669	70.00		1.45	R5.0	51.70
42	352.00	27,646	40.00	-25.00	3.23	R5.0	22.60
43	353.00	200,612	40.00	5.00	2.43	R4.0	26.40
44	354.00	57,168	60.00		1.69	L4.0	45.70
45	355.00	81,185	45.00	-25.00	2.85	R4.0	27.70
46	356.00	101,673	50.00	10.00	1.85	R5.0	30.60
47	359.00	318	70.00		1.52	R5.0	29.70
48	Subtotal Transmission	484,271					
49	361.00	14,863	45.00	-25.00	2.83	R2.0	31.30
50	362.00	119,805	40.00	5.00	2.43	R2.5	26.00

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	364.00	172,815	35.00	-15.00	3.35	L2.0	24.50
13	365.00	90,242	45.00	-10.00	2.48	R1.0	34.00
14	366.00	31,606	50.00		2.02	R2.5	40.60
15	367.00	125,667	30.00		3.38	R4.0	22.00
16	368.00	255,276	25.00	5.00	3.92	R4.0	15.30
17	369.00	44,797	25.00	-20.00	4.94	R5.0	14.90
18	370.00	38,840	35.00		2.90	L2.0	25.40
19	371.10	359	10.00	30.00	7.00	LO	9.00
20	371.20	1,856	13.00		7.89	LO	8.40
21	373.00	3,886	25.00	-15.00	4.70	L2.0	17.10
22	Subtotal Distribution	900,012					
23	390.11	24,083	60.00		1.68	R4.0	59.50
24	390.12	26,043	45.00		2.22	R1.5	36.50
25	390.20	6,755	20.00	-5.00	5.37	R3.0	13.50
26	391.10	10,814	20.00	5.00	4.82	R0.5	15.00
27	391.20	33,310	8.00	5.00	12.21	R2.0	4.50
28	391.21	6,139	8.00	5.00	12.21	R2.0	4.50
29	392.10	241	8.00	15.00	10.76	R0.5	5.50
30	392.30	1,855	15.00	50.00	3.79	S2.0	15.00
31	392.40	14,080	7.00	25.00	11.03	R2.5	4.20
32	392.50	318	7.00	15.00	12.53	R2.5	4.70
33	392.60	18,915	14.00	30.00	5.12	R0.5	9.50
34	392.70	3,233	14.00	30.00	5.05	R0.5	11.40
35	392.90	2,950	17.00	30.00	4.20	R1.0	11.90
36	393.00	1,012	25.00	15.00	3.44	R0.5	19.10
37	394.00	3,529	20.00	10.00	4.60	L3.0	13.30
38	395.00	8,733	20.00	5.00	4.83	R5.0	13.90
39	396.00	6,348	20.00	40.00	3.05	R1.0	14.30
40	397.10	6,985	25.00	-10.00	4.46	L2.0	19.40
41	397.20	8,431	20.00		5.14	L3.0	12.00
42	397.30	3,163	20.00		5.16	L4.0	11.60
43	397.40	866	20.00	-10.00	5.50	L2.0	19.50
44	398.00	2,000	17.00	5.00	5.72	L1.5	11.50
45	Subtotal General	189,803					
46	Total Plant	2,992,445					
47							
48							
49							
50							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

REGULATORY COMMISSION EXPENSES

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

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Federal Energy Regulatory Commission:				
2	Annual administrative charges	2,835,971		2,835,971	
3					
4	General Regulatory Expenses:				
5	Other Expenses		473,861	473,861	
6					
7	Regulatory Commission Expenses - Idaho				
8	Intervenor Funding (various cases)		32,314	32,314	
9	Other Expenses		109,833	109,833	
10					
11	Regulatory Commission Expenses - Oregon				
12	Other Expenses		-210	-210	
13					
14	Regulatory Commission Expenses - Nevada				
15	General Regulatory Expenses		22,020	22,020	
16					
17					
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45					
46	TOTAL	2,835,971	637,818	3,473,789	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

REGULATORY COMMISSION EXPENSES (Continued)

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

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
Electric	928	2,835,971					2
							3
							4
Electric	928	473,861					5
							6
							7
Electric	928	32,314					8
Electric	928	109,833					9
							10
							11
Electric	928	-210					12
							13
							14
Electric	928	22,020					15
							16
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		3,473,789					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

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

Classifications:

A. Electric R, D & D Performed Internally:
(1) Generation
a. hydroelectric
i. Recreation fish and wildlife
ii Other hydroelectric
b. Fossil-fuel steam
c. Internal combustion or gas turbine
d. Nuclear
e. Unconventional generation
f. Siting and heat rejection

(3) Transmission
a. Overhead
b. Underground
(4) Distribution
(5) Environment (other than equipment)
(6) Other (Classify and include items in excess of $5,000.)
(7) Total Cost Incurred
B. Electric, R, D & D Performed Externally:
(1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	A. Electric R, D & D Performed internally:	
2	(1) Generation	
3	e. unconventional generation	Acoustic Flow Meter - Brownlee
4		Water Forecasting Model
5		Winter Kennedy Calibration
6		Remote PDA Testing Pilot
7		
8		
9		
10		Northwest Energy Efficiency Alliance
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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
12,893		107	12,893		3
81,379		107	81,379		4
12,598		535	12,598		5
91,685		107	91,685		6
					7
					8
					9
	1,277,274	107	1,277,274		10
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

DISTRIBUTION OF SALARIES AND WAGES

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

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	6,955,668		
4	Transmission	4,653,347		
5	Distribution	13,203,110		
6	Customer Accounts	8,514,591		
7	Customer Service and Informational	3,091,725		
8	Sales			
9	Administrative and General	25,747,427		
10	TOTAL Operation (Enter Total of lines 3 thru 9)	62,165,868		
11	Maintenance			
12	Production	4,886,525		
13	Transmission	2,339,445		
14	Distribution	7,221,547		
15	Administrative and General	496,583		
16	TOTAL Maint. (Total of lines 12 thru 15)	14,944,100		
17	Total Operation and Maintenance			
18	Production (Enter Total of lines 3 and 12)	11,842,193		
19	Transmission (Enter Total of lines 4 and 13)	6,992,792		
20	Distribution (Enter Total of lines 5 and 14)	20,424,657		
21	Customer Accounts (Transcribe from line 6)	8,514,591		
22	Customer Service and Informational (Transcribe from line 7)	3,091,725		
23	Sales (Transcribe from line 8)			
24	Administrative and General (Enter Total of lines 9 and 15)	26,244,010		
25	TOTAL Oper. and Maint. (Total of lines 18 thru 24)	77,109,968	3,039,751	80,149,719
26	Gas			
27	Operation			
28	Production-Manufactured Gas			
29	Production-Nat. Gas (Including Expl. and Dev.)			
30	Other Gas Supply			
31	Storage, LNG Terminaling and Processing			
32	Transmission			
33	Distribution			
34	Customer Accounts			
35	Customer Service and Informational			
36	Sales			
37	Administrative and General			
38	TOTAL Operation (Enter Total of lines 28 thru 37)			
39	Maintenance			
40	Production-Manufactured Gas			
41	Production-Natural Gas			
42	Other Gas Supply			
43	Storage, LNG Terminaling and Processing			
44	Transmission			
45	Distribution			
46	Administrative and General			
47	TOTAL Maint. (Enter Total of lines 40 thru 46)			

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 Terminaling 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)	77,109,968	3,039,751	80,149,719
63	Utility Plant			
64	Construction (By Utility Departments)			
65	Electric Plant	28,577,712		28,577,712
66	Gas Plant			
67	Other (provide details in footnote):			
68	TOTAL Construction (Total of lines 65 thru 67)	28,577,712		28,577,712
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	Misc Deferred & Regulatory assets	772,008		772,008
76	Paid Absences	12,295,832		12,295,832
77	Expense of non-utility operations	2,256,888		2,256,888
78	Other Clearing Accounts	361		361
79				
80				
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	15,325,089		15,325,089
96	TOTAL SALARIES AND WAGES	121,012,769	3,039,751	124,052,520

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

COMMON UTILITY PLANT AND EXPENSES

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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)	12,894,068
3	Steam	7,242,811			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	106,282
5	Hydro-Conventional	6,068,478			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	1,962,222
7	Other	43,433			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	13,354,722	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
10	Purchases	2,855,620	27	Total Energy Losses	1,229,819
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	16,192,391
12	Received	477,026			
13	Delivered	496,849			
14	Net Exchanges (Line 12 minus line 13)	-19,823			
15	Transmission For Other (Wheeling)				
16	Received	4,712,790			
17	Delivered	4,710,918			
18	Net Transmission for Other (Line 16 minus line 17)	1,872			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	16,192,391			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

MONTHLY PEAKS AND OUTPUT

1. 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 in column (b) the system's energy output for each month such that the total on Line 41 matches the total on Line 20.
3. Report in column (c) a monthly breakdown of the Non-Requirements Sales For Resale reported on Line 24. include in the monthly amounts any energy losses associated with the sales so that the total on Line 41 exceeds the amount on Line 24 by the amount of losses incurred (or estimated) in making the Non-Requirements Sales for Resale.
4. Report in column (d) the system's monthly maximum megawatt Load (60-minute integration) associated with the net energy for the system defined as the difference between columns (b) and (c)
5. Report in columns (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	1,614,296	418,746	2,131	29	8 AM
30	February	1,165,978	112,210	2,074	5	8 AM
31	March	1,310,521	260,652	1,917	4	8 AM
32	April	1,161,689	207,684	1,719	18	8 AM
33	May	1,314,295	136,529	2,365	30	5 PM
34	June	1,454,941	63,697	2,822	26	4 PM
35	July	1,687,221	86,813	2,963	12	4 PM
36	August	1,504,329	110,695	2,529	15	6PM
37	September	1,291,805	165,481	2,310	3	6 PM
38	October	1,218,042	164,615	1,934	31	8 AM
39	November	1,125,493	62,902	1,912	1	8 AM
40	December	1,343,781	172,198	1,942	19	7 PM
41	TOTAL	16,192,391	1,962,222			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 37) and average cost per unit of fuel burned (Line 40) must be consistent with charges to expense accounts 501 and 547 (Line 41) as show on Line 19. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Jim Bridger* (b)			Plant Name: *Boardman* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Semi-Outdoor Boiler			Conventional		
3	Year Originally Constructed	1974			1980		
4	Year Last Unit was Installed	1979			1980		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	770.50			56.05		
6	Net Peak Demand on Plant - MW (60 minutes)	700			59		
7	Plant Hours Connected to Load	8760			6950		
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	4945008000			352608000		
13	Cost of Plant: Land and Land Rights	487488			106610		
14	Structures and Improvements	62044801			13439132		
15	Equipment Costs	336012330			50588732		
16	Total Cost	398544619			64134474		
17	Cost per KW of Installed Capacity (line 5)	517.2545			1144.2368		
18	Production Expenses: Oper, Supv, & Engr	131088			639184		
19	Fuel	60977531			5118059		
20	Coolants and Water (Nuclear Plants Only)	0			0		
21	Steam Expenses	1829393			0		
22	Steam From Other Sources	0			0		
23	Steam Transferred (Cr)	0			0		
24	Electric Expenses	0			0		
25	Misc Steam (or Nuclear) Power Expenses	1216170			166302		
26	Rents	95703			418463		
27	Allowances	0			0		
28	Maintenance Supervision and Engineering	7483			1698776		
29	Maintenance of Structures	0			0		
30	Maintenance of Boiler (or reactor) Plant	5808682			0		
31	Maintenance of Electric Plant	2247069			0		
32	Maintenance of Misc Steam (or Nuclear) Plant	8694418			13343		
33	Total Production Expenses	81007537			8054127		
34	Expenses per Net KWh	0.0164			0.0228		
35	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal		Oil	Coal		Oil
36	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons		Barrels	Tons		Barrels
37	Quantity (units) of Fuel Burned	2837767	0	14860	201685	0	1404
38	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	9110	0	140000	8697	0	138800
39	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	20.572	0.000	32.587	23.417	0.000	33.735
40	Average Cost of Fuel per Unit Burned	20.516	0.000	39.273	23.275	0.000	38.256
41	Average Cost of Fuel Burned per Million BTU	1.126	0.000	6.679	1.338	0.000	6.561
42	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.012	0.000	0.000	0.015	0.000
43	Average BTU per KWh Net Generation	0.000	10474.000	0.000	0.000	9973.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 24 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 31, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Valmy* (d)	Plant Name: *Danskin* (e)	Plant Name: (f)	Line No.
Steam	Gas Turbine		1
Outdoor	Conventional		2
1981	2001		3
1985	2001		4
283.50	90.00	0.00	5
272	103	0	6
8756	753	0	7
0	100000	0	8
0	0	0	9
0	0	0	10
0	3	0	11
1945195000	43368000	0	12
681105	218768	0	13
53521664	1194403	0	14
244074853	48386719	0	15
298277622	49799890	0	16
1052.1257	553.3321	0.0000	17
243469	68349	0	18
32250861	4521761	0	19
0	0	0	20
1918262	0	0	21
0	0	0	22
0	0	0	23
1039067	253390	0	24
2427660	295948	0	25
218504	0	0	26
0	0	0	27
149456	0	0	28
153018	144	0	29
2641884	0	0	30
560958	0	0	31
164499	0	0	32
41767638	5139592	0	33
0.0215	0.1185	0.0000	34

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
Coal		Oil	Gas						35
Tons		Barrels	MCF						36
873279	0	3694	545024	0	0	0	0	0	37
10875	0	138778	1029	0	0	0	0	0	38
36.172	0.000	37.107	8.538	0.000	0.000	0.000	0.000	0.000	39
35.569	0.000	36.691	8.538	0.000	0.000	0.000	0.000	0.000	40
1.635	0.000	6.295	8.296	0.000	0.000	0.000	0.000	0.000	41
0.000	0.017	0.000	0.000	0.104	0.000	0.000	0.000	0.000	42
0.000	9775.000	0.000	0.000	12567.000	0.000	0.000	0.000	0.000	43

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

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

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

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

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/2003	Year of Report Dec. 31, 2002

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 plan, 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)	73	60
7	Plant Hours Connect to Load	4,819	8,760
8	Net Plant Capability (in megawatts)	0	0
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	209,541,000	298,680,000
13	Cost of Plant	0	0
14	Land and Land Rights	875,615	463,556
15	Structures and Improvements	11,812,406	647,382
16	Reservoirs, Dams, and Waterways	4,242,904	7,428,168
17	Equipment Costs	30,804,885	6,463,550
18	Roads, Railroads, and Bridges	306,333	486,477
19	TOTAL cost (Total of 14 thru 18)	48,042,143	15,489,133
20	Cost per KW of Installed Capacity (line 5)	520.4999	206.5218
21	Production Expenses	0	0
22	Operation Supervision and Engineering	199,983	123,571
23	Water for Power	826,835	159,401
24	Hydraulic Expenses	81,923	59,926
25	Electric Expenses	24,983	14,185
26	Misc Hydraulic Power Generation Expenses	162,757	78,143
27	Rents	168	2,739
28	Maintenance Supervision and Engineering	62,471	43,493
29	Maintenance of Structures	201,724	56,973
30	Maintenance of Reservoirs, Dams, and Waterways	11,012	55,390
31	Maintenance of Electric Plant	140,419	112,333
32	Maintenance of Misc Hydraulic Plant	102,778	111,050
33	Total Production Expenses (total 22 thru 32)	1,815,053	817,204
34	Expenses per net KWh	0.0087	0.0027

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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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 plan, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 1971 Plant Name: Hells Canyon (b)	FERC Licensed Project No. 2726 Plant Name: Malad (c)
1	Kind of Plant (Run-of-River or Storage)	Storage	Run-of-River
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Outdoor
3	Year Originally Constructed	1967	1948
4	Year Last Unit was Installed	1967	1948
5	Total installed cap (Gen name plate Rating in MW)	391.50	21.77
6	Net Peak Demand on Plant-Megawatts (60 minutes)	421	25
7	Plant Hours Connect to Load	8,760	8,697
8	Net Plant Capability (in megawatts)	0	0
9	(a) Under Most Favorable Oper Conditions	450	24
10	(b) Under the Most Adverse Oper Conditions	137	21
11	Average Number of Employees	4	2
12	Net Generation, Exclusive of Plant Use - Kwh	1,620,733,000	165,052,000
13	Cost of Plant	0	0
14	Land and Land Rights	1,563,504	205,376
15	Structures and Improvements	1,710,021	2,122,897
16	Reservoirs, Dams, and Waterways	52,511,953	3,371,066
17	Equipment Costs	14,226,490	2,806,524
18	Roads, Railroads, and Bridges	819,192	304,683
19	TOTAL cost (Total of 14 thru 18)	70,831,160	8,810,546
20	Cost per KW of Installed Capacity (line 5)	180.9225	404.7104
21	Production Expenses	0	0
22	Operation Supervision and Engineering	282,584	90,455
23	Water for Power	34,031	373,963
24	Hydraulic Expenses	190,817	45,516
25	Electric Expenses	65,453	40,913
26	Misc Hydraulic Power Generation Expenses	112,442	43,518
27	Rents	58,781	16
28	Maintenance Supervision and Engineering	100,486	14,288
29	Maintenance of Structures	53,695	13,074
30	Maintenance of Reservoirs, Dams, and Waterways	24,571	32,282
31	Maintenance of Electric Plant	166,866	17,410
32	Maintenance of Misc Hydraulic Plant	463,115	43,598
33	Total Production Expenses (total 22 thru 32)	1,552,841	715,033
34	Expenses per net KWh	0.0010	0.0043

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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 plan, 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	8,760	8,492
8	Net Plant Capability (in megawatts)	0	0
9	(a) Under Most Favorable Oper Conditions	39	13
10	(b) Under the Most Adverse Oper Conditions	32	11
11	Average Number of Employees	4	2
12	Net Generation, Exclusive of Plant Use - Kwh	193,119,000	84,464,000
13	Cost of Plant	0	0
14	Land and Land Rights	172,970	311,407
15	Structures and Improvements	1,403,295	1,138,033
16	Reservoirs, Dams, and Waterways	3,517,649	512,401
17	Equipment Costs	4,582,633	2,030,100
18	Roads, Railroads, and Bridges	29,359	51,383
19	TOTAL cost (Total of 14 thru 18)	9,705,906	4,043,324
20	Cost per KW of Installed Capacity (line 5)	281.3306	323.4659
21	Production Expenses	0	0
22	Operation Supervision and Engineering	225,604	77,169
23	Water for Power	26,935	8,391
24	Hydraulic Expenses	129,491	18,612
25	Electric Expenses	18,293	10,900
26	Misc Hydraulic Power Generation Expenses	109,730	53,657
27	Rents	40	39
28	Maintenance Supervision and Engineering	53,730	33,188
29	Maintenance of Structures	35,589	33,026
30	Maintenance of Reservoirs, Dams, and Waterways	30,731	3,017
31	Maintenance of Electric Plant	241,213	52,432
32	Maintenance of Misc Hydraulic Plant	106,335	51,318
33	Total Production Expenses (total 22 thru 32)	977,691	341,749
34	Expenses per net KWh	0.0051	0.0040

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

FERC Licensed Project No. 1971 Plant Name: Brownlee (d)	FERC Licensed Project No. 2848 Plant Name: Cascade (e)	FERC Licensed Project No. 1971 Plant Name: Oxbow (f)	Line No.
Storage	Run-of-River	Storage	1
Outdoor	Outdoor	Outdoor	2
1958	1983	1961	3
1980	1984	1961	4
585.40	12.42	190.00	5
641	12	219	6
8,760	8,760	8,760	7
0	0	0	8
728	14	220	9
220	1	202	10
7	2	5	11
1,839,334,000	722,000	822,572,000	12
0	0	0	13
5,654,942	82,142	866,938	14
30,080,032	7,364,154	9,615,323	15
66,699,271	3,145,630	30,230,850	16
50,220,969	12,683,831	14,659,091	17
518,444	122,668	565,842	18
153,173,658	23,398,425	55,938,044	19
261.6564	1,883.9312	294.4108	20
0	0	0	21
669,363	121,732	333,520	22
75,267	28,394	34,230	23
482,553	22,753	234,586	24
207,098	45,538	179,482	25
249,338	66,499	102,493	26
204,857	118	35,212	27
136,499	69,718	171,176	28
168,689	24,750	235,911	29
51,244	361	217,101	30
243,729	64,897	191,613	31
431,970	51,333	308,703	32
2,920,607	496,093	2,044,027	33
0.0016	0.6871	0.0025	34

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

FERC Licensed Project No. 2055 Plant Name: C J Strike (d)	FERC Licensed Project No. 503 Plant Name: Swan Falls (e)	FERC Licensed Project No. 18 Plant Name: Twin Falls (f)	Line No.
Run-of-River	Run-of-River	Run-of-River	1
Outdoor	Conventional	Conventional	2
1952	1910	1935	3
1952	1994	1995	4
82.80	25.00	52.74	5
85	19	36	6
8,760	8,757	7,017	7
0	0	0	8
89	26	54	9
84	14	50	10
5	4	5	11
363,607,000	112,913,000	43,211,000	12
0	0	0	13
2,052,202	51,675	255,499	14
2,666,522	25,118,690	10,808,047	15
9,739,793	13,583,476	7,908,304	16
6,760,098	30,204,371	19,756,997	17
222,132	835,946	1,917,603	18
21,440,747	69,794,158	40,646,450	19
258.9462	2,791.7663	770.6949	20
0	0	0	21
578,854	218,728	317,727	22
45,679	19,641	23,097	23
169,199	105,314	100,310	24
13,933	23,477	18,219	25
136,453	79,991	138,101	26
70,981	6,988	1,021	27
45,175	55,167	50,765	28
88,921	66,155	55,526	29
61,123	44,857	90,296	30
76,588	136,127	197,373	31
124,612	137,270	70,690	32
1,411,518	893,715	1,063,125	33
0.0039	0.0079	0.0246	34

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

FERC Licensed Project No. 1971 Plant Name: Common Facilities (d)	FERC Licensed Project No. 2061 Plant Name: Lower Salmon (e)	FERC Licensed Project No. 2899 Plant Name: Milner (f)	Line No.
	Run-of-River	Run-of-River	1
	Outdoor	Conventional	2
	1949	1992	3
	1949	1992	4
0.00	60.00	59.45	5
0	43	14	6
0	8,760	6,231	7
0	0	0	8
0	70	59	9
0	63	1	10
0	7	2	11
0	193,582,000	24,915,000	12
0	0	0	13
80,646	403,335	138,100	14
10,990,609	839,658	10,327,358	15
13,556,785	6,458,575	17,141,809	16
974,268	6,304,851	27,329,297	17
99,051	88,693	501,877	18
25,701,359	14,095,112	55,438,441	19
0.0000	234.9185	932.5221	20
0	0	0	21
0	705,448	195,056	22
0	44,691	1,326,422	23
3,020,580	145,270	100,907	24
0	125,513	39,548	25
0	146,969	174,786	26
0	1,227	1,381	27
0	49,136	65,387	28
0	69,854	37,335	29
0	16,394	49,581	30
0	172,220	230,808	31
0	109,673	50,279	32
3,020,580	1,586,395	2,271,490	33
0.0000	0.0082	0.0912	34

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

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

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. Plant Name: (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Total cost (total 13 thru 19)	
21	Cost per KW of installed cap (line 20/line4)	
22	Production Expenses	
23	Operation Supervision and Engineering	
24	Water for Power	
25	Pumped Storage Expenses	
26	Electric Expenses	
27	Misc Pumped Storage Power generation Expenses	
28	Rents	
29	Maintenance Supervision and Engineering	
30	Maintenance of Structures	
31	Maintenance of Reservoirs, Dams, and Waterways	
32	Maintenance of Electric Plant	
33	Maintenance of Misc Pumped Storage Plant	
34	Production Exp Before Pumping Exp (23 thru 33)	
35	Pumping Expenses	
36	Total Production Exp (total 34 and 35)	
37	Expenses per KWh (line 36/line 9)	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 35 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 35, 36 and 37 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
			1
			2
			3
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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	2.0	15,022	1,037,437
3	Thousand Springs	1912	8.80	6.7	49,316	4,535,203
4						
5						
6	Internal Combustion:					
7	Salmon Diesel (1)	1967	5.00	5.5	65	663,479
8	Danskin	2001				49,799,889
9						
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17						
18	(1) Salmon units are classified as standby.					
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

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 Per MW Inst Capacity (g)	Operation Exc'l. Fuel (h)	Production Expenses: Fuel (i)	Production Expenses: Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
414,975	89,578		19,449			2
515,364	90,332		354,932			3
						4
						5
						6
132,696				Diesel		7
						8
						9
						10
						11
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Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/2003	Year of Report Dec. 31, 2002

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Boardman	Slatt	500.00	500.00	S Tower	1.78		1
2								
3	Borah	Midpoint	345.00	500.00	S Tower	85.44		1
4	Jim Bridger	Goshen	345.00	345.00	S Tower	225.88		1
5	State Line	Midpoint	345.00	345.00	S Tower	76.15		2
6	Kinport	Borah	345.00	345.00	S Tower	27.30		1
7	Midpoint	Borah #1	345.00	345.00	H Wood	79.55		1
8	Midpoint	Borah #2	345.00	345.00	H Wood	77.97		2
9	Adelaide Tap	Adelaide	345.00	345.00	H Wood	2.66		2
10								
11	Quartz	LaGrande	230.00	230.00	H Wood	46.42		1
12	Midpoint	Hunt	230.00	230.00	S Tower	0.60		2
13	Brady	Antelope	230.00	230.00	H Wood	56.49		1
14	Brady	Treasureton	230.00	230.00	H Wood	0.11		1
15	Brady #1 & #2	Kinport	230.00	230.00	S Tower	18.48		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	74.10		1
18	Mora	Bowmont	138.00	230.00	S P Wood	5.35		1
19	"	"	138.00	230.00	H Wood	10.85		1
20	Jim Bridger	Point of Rocks	230.00	230.00	H Wood	2.78		1
21	Boise Bench	Caldwell	230.00	230.00	S Tower	4.46		1
22	" "	"	230.00	230.00	H Wood	33.75		1
23	Boise Bench	Cloverdale	230.00	230.00	S Tower	15.69		2
24	Boardman	Dalreed Sub	230.00	230.00	H Wood	1.67		1
25	Caldwell	Ontario	230.00	230.00	H Wood	27.34		1
26	" "	"	230.00	230.00	S Tower	3.26		1
27	Boise Bench	Midpoint #1	230.00	230.00	S Tower	0.86		1
28	" "	"	230.00	230.00	H Wood	108.47		1
29	Brownlee	Quartz Jct	230.00	230.00	S Tower	1.52		1
30	"	" "	230.00	230.00	H Wood	41.65		1
31	Brownlee	Boise Bench #1 & #2	230.00	230.00	S Tower	100.09		2
32	Oxbow	Brownlee	230.00	230.00	S Tower	10.44		2
33	Boise Bench	Midpoint #2	230.00	230.00	S Tower	3.42		1
34	" "	"	230.00	230.00	H Wood	101.94		1
35	Oxbow	Pallette Jct	230.00	230.00	S Tower	20.14		2
36					TOTAL	4,656.75		147

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Pallette Jct	Imnaha	230.00	230.00	H Wood	24.57		2
2	Hells Canyon	Palette Jct	230.00	230.00	S Tower	8.27		2
3	Brownlee	Boise Bench	230.00	230.00	S Tower	102.56		2
4	Boise Bench	Midpoint #3	230.00	230.00	H Wood	106.65		1
5	Palette Jct	Enterprise	230.00	230.00	H Wood	29.62		1
6	Borah	Brady #2	230.00	230.00	S Tower	0.43		1
7	"	"	230.00	230.00	H Wood	3.59		1
8	Borah	Brady #1	230.00	230.00	H Wood	3.96		1
9								
10	Goshen	State Line	161.00	161.00	H Wood	90.44		1
11	Don	Goshen	161.00	161.00	S Tower	2.40		2
12	"	"	161.00	161.00	H Wood	46.53		2
13								
14	American Falls Power Plant	Adelaide	138.00	138.00	H Wood	84.82		2
15	"	"	138.00	138.00	S P Wood	2.58		2
16	Minidoka Loop	"	138.00	138.00	S Tower	1.54		2
17	Nampa	Caldwell	138.00	138.00	S P Wood	10.79		2
18	Upper Salmon	Mountain Home Jct		138.00	H Wood	4.41		1
19	"	"	138.00	138.00	H Wood	54.59		1
20	"	Cliff	138.00	138.00	H Wood	30.94		1
21	Eastgate	Russet	138.00	138.00	S P Wood	2.12		1
22	Brady	Fremont	138.00	138.00	S Tower	1.00		2
23	"	"	138.00	138.00	H Wood	27.98		2
24	"	"	138.00	138.00	S P Wood	20.64		2
25	King	Lower Malad	138.00	138.00	H Wood	85.20		2
26	Emmett Jct	Payette	138.00	138.00	H Wood	60.87		2
27	Mountain Home AFB Tap		138.00	138.00	H Wood	6.23		1
28	Ontario	Quartz	138.00	138.00	H Wood	73.61		1
29	King	American Falls PP	138.00	138.00	S Tower	1.02		2
30	"	"	138.00	138.00	H Wood	135.81		1
31	"	"	138.00	138.00	S P Wood	3.71		1
32								
33								
34	Duffin	Clawson	138.00	138.00	H Wood	6.28		1
35	American Falls	Brady Tie	138.00	138.00	H Wood	0.38		1
36					TOTAL	4,656.75		147

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/2003	Year of Report Dec. 31, 2002

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Upper Salmon A-B	King	138.00	138.00	H Wood	6.05		1
2	Upper Salmon B	Wells	138.00	138.00	H Wood	125.70		1
3	King	Wood River	138.00	138.00	H Wood	73.98		1
4	Boise Bench	Grove	138.00	138.00	S P Wood	10.48		2
5	Quartz	John Day	138.00	138.00	H Wood	67.45		1
6	Sinker Creek Tap		138.00	138.00	H Wood	2.80		1
7	Mora	Cloverdale	138.00	138.00	H Wood	2.57		1
8	"	"	138.00	138.00	S P Wood	22.50		1
9	Stoddard Jct	Stoddard Sub	138.00	138.00	S P Steel	3.80		1
10	Fossil Gulch Tap		138.00	138.00	H Wood	2.08		1
11	Wood River	Midpoint	138.00	138.00	H Wood	53.22		2
12	"	"	138.00	138.00	S P Wood	16.74		2
13	Oxbow	McCall	138.00	138.00	H Wood	38.61		1
14	"	"	138.00	138.00	S P Wood	1.73		1
15	Lowell Jct	Nampa	138.00	138.00	S P Wood	6.60		2
16	Hunt	Milner	138.00	138.00	S P Wood	19.62		1
17	Strike	Bruneau Bridge	138.00	138.00	H Wood	13.51		1
18	American Falls	Kramer Sub	138.00	138.00	S P Wood	18.42		2
19	Pingree	Haven	138.00	138.00	S P Wood	11.77		1
20	Midpoint	Twin Falls	138.00	138.00	S P Wood	25.42		2
21	Twin Falls	Russett	138.00	138.00	S P Wood	1.73		1
22	Blackfoot	Aiken	138.00	138.00	S P Wood	6.36		2
23	Peterson	Tendoy	138.00	138.00	H Wood	57.27		1
24	Eastgate Tap	Eastgate	138.00	138.00	S P Wood	7.39		1
25	Boise Bench	Mora	138.00	138.00	H Wood	13.28		2
26	Bowmont-Caldwell	Simplot Sub	138.00	138.00	S P Wood	0.54		1
27	Gary Lane	Eagle	138.00	138.00	S P Wood	6.81		1
28	Locust Grove	Blackcat Sub	138.00	138.00	S P Steel	7.01		1
29	Boise Bench	Butler Sub	138.00	138.00	S P Steel	2.97		2
30	Kinport	Don #1	138.00	138.00	S Tower	1.42		2
31	Twin Falls PP Tap		138.00	138.00	H Wood	1.03		1
32	American Falls PP	Amercian Falls Trans ST	138.00	138.00	S P Steel	0.43		1
33	Lower Salmon	King Tie	138.00	138.00	H Wood	0.25		1
34	C J Strike	Strike Jct	138.00	138.00	S Tower	4.48		2
35	Strike Jct	Mountain Home Jct	138.00	138.00	H Wood	26.72		1
36					TOTAL	4,656.75		147

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1								
2	Strike Jct	Bowmont		138.00	H Wood	0.06		1
3	"	"	138.00	138.00	S Tower	0.36		1
4	Strike Jct	Bowmont	138.00	138.00	H Wood	68.45		1
5	Lucky Peak	Lucky Peak Jct	138.00	138.00	H Wood	4.51		2
6	Bliss	King	138.00	138.00	H Wood	0.29		1
7	"	"	138.00	138.00	H Wood	10.57		1
8	Milner Deadend	Milner PP	138.00	138.00	S P Wood	1.36		1
9	Swan Falls Tap		138.00	138.00	H Wood	1.00		1
10								
11								
12								
13	Hines	BPA (Harney)	115.00	115.00	H Wood	3.41		1
14								
15								
16	69 Kv Lines		69.00	69.00	H Wood	233.85		1
17	69 Kv Lines		69.00	69.00	S P Wood	936.44		1
18								
19								
20	46 Kv Lines		46.00	46.00	S P Wood	434.16		1
21								
22								
23								
24								
25								
26								
27								
28								
29	Expenses of all Lines							
30								
31								
32								
33								
34								
35								
36					TOTAL	4,656.75		147

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
2X1780 ACSR		446,708	446,708					1
								2
1272 ACSR	256,381	21,776,998	22,033,379					3
1272 ACSR	483,309	15,515,607	15,998,916					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	60,814	5,425,266	5,486,080					7
715.5 ACSR	64,851	6,019,155	6,084,006					8
715.5 ACSR	51,448	347,946	399,394					9
								10
795 ACSR	51,414	2,071,529	2,122,943					11
715.5 ACSR	9,145	395,951	405,096					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	1,302,697	14,658,240	15,960,937					17
715.5 ACSR	29,522	770,560	800,082					18
715.5 ACSR								19
1272 ACSR	1,899	212,523	214,422					20
1272 ACSR	809,054	2,761,586	3,570,640					21
715.5 ACSR								22
1272 ACSR	2,976,323	6,610,447	9,586,770					23
795 AAC		80,895	80,895					24
2X954 ACSR	194,763	5,378,763	5,573,526					25
1272 ACSR								26
715.5 ACSR	236,147	3,381,261	3,617,408					27
715.5 ACSR								28
795 ACSR	42,995	1,782,886	1,825,881					29
795 ACSR								30
VARIOUS	635,371	13,458,530	14,093,901					31
1272 ACSR	6,033	1,030,235	1,036,268					32
715.5 ACSR	202,760	4,369,305	4,572,065					33
VARIOUS								34
1272 ACSR	23,308	1,884,063	1,907,371					35
	15,908,723	240,346,731	256,255,454	5,179,735	3,076,074	1,648,202	9,904,011	36

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/2003	Year of Report Dec. 31, 2002

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1272 ACSR	138,477	1,193,255	1,331,732					1
1272 ACSR	10,737	1,214,847	1,225,584					2
954 ACSR	170,694	5,790,873	5,961,567					3
715.5 ACSR	243,290	4,563,114	4,806,404					4
1272 ACSR	51,122	1,633,094	1,684,216					5
1272 ACSR	3,068	200,632	203,700					6
715.5 ACSR								7
1272 ACSR	10,064	180,008	190,072					8
								9
250 COPPER	16,155	638,091	654,246					10
715.5 ACSR	76,041	1,751,397	1,827,438					11
397.5 ACSR								12
								13
250 COPPER	26,507	2,351,943	2,378,450					14
250 COPPER								15
715.5 ACSR	15,088	249,232	264,320					16
795 AAC	157,432	1,510,370	1,667,802					17
795 ACSR	47,687	1,620,265	1,667,952					18
VARIOUS								19
795 ACSR	43,568	764,183	807,751					20
795 AAC	270,823	557,504	828,327					21
VARIOUS	564,932	3,425,725	3,990,657					22
"								23
"								24
"	76,823	1,279,357	1,356,180					25
"	30,918	1,320,023	1,350,941					26
397.5 ACSR	1,955		1,955					27
VARIOUS	34,428	1,460,111	1,494,539					28
715.5 ACSR	134,494	3,897,526	4,032,020					29
715.5 ACSR								30
715.5 ACSR								31
								32
								33
4\0	4,191	309,827	314,018					34
954 ACSR		13,539	13,539					35
	15,908,723	240,346,731	256,255,454	5,179,735	3,076,074	1,648,202	9,904,011	36

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/2003	Year of Report Dec. 31, 2002

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
250 COPPER	2,740	81,732	84,472					1
VARIOUS	28,490	1,745,804	1,774,294					2
"	173,683	2,169,112	2,342,795					3
"	225,602	1,673,463	1,899,065					4
397.5 ACSR	92,173	2,397,230	2,489,403					5
VARIOUS	20	77,199	77,219					6
715.5 ACSR	1,302,173	4,811,134	6,113,307					7
VARIOUS								8
1272 ACSR								9
250 COPPER	450	63,439	63,889					10
397.5 ACSR	281,064	6,368,667	6,649,731					11
397.5 ACSR								12
397.5 ACSR	84,183	1,738,664	1,822,847					13
397.5 ACSR								14
715.5 ACSR	127,369	950,694	1,078,063					15
715.5 ACSR	3,324	1,070,939	1,074,263					16
397.5 ACSR	14,927	586,095	601,022					17
715.5 ACSR	13,734	991,714	1,005,448					18
397.5 ACSR	11,213	778,092	789,305					19
VARIOUS	54,848	2,949,190	3,004,038					20
715.5 ACSR	16,790	206,158	222,948					21
715.5 ACSR	13,616	448,302	461,918					22
397.5 ACSR	395,696	3,449,949	3,845,645					23
715.5 ACSR	45,989	1,057,571	1,103,560					24
715.5 ACSR	14,697	632,718	647,415					25
795 AAC		49,642	49,642					26
795 AAC	489,037	1,965,600	2,454,637					27
1272 ACSR	935,725	2,992,444	3,928,169					28
1272 ACSR	10,396	554,887	565,283					29
715.5 ACSR	1,174	212,777	213,951					30
250 COPPER	58	53,888	53,946					31
715.5 ACSR		76,560	76,560					32
397.5 ACSR		4,406	4,406					33
715.5 ACSR	1,074	253,872	254,946					34
397.5 ACSR	4,355	475,486	479,841					35
	15,908,723	240,346,731	256,255,454	5,179,735	3,076,074	1,648,202	9,904,011	36

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/2003	Year of Report Dec. 31, 2002

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)	
								1
715.5 ACSR	29,902	1,488,107	1,518,009					2
715.5 ACSR								3
								4
715.5 ACSR	7	152,852	152,859					5
VARIOUS								6
715.5 ACSR	5,620	445,666	451,286					7
715.5 ACSR	2,814	183,606	186,420					8
397.5 ACSR	12,885	261,511	274,396					9
397.5 ACSR								10
								11
								12
397.5 ACSR	1,978	63,404	65,382					13
								14
								15
VARIOUS	723,405	25,050,301	25,773,706					16
"								17
								18
								19
VARIOUS	176,265	7,130,171	7,306,436					20
								21
								22
								23
								24
								25
								26
								27
								28
				5,179,735	3,076,074	1,648,202	9,904,011	29
								30
								31
								32
								33
								34
								35
	15,908,723	240,346,731	256,255,454	5,179,735	3,076,074	1,648,202	9,904,011	36

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)	(c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	No New Lines Added for 2002						
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
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39							
40							
41							
42							
43							
44	TOTAL						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

TRANSMISSION LINES ADDED DURING YEAR (Continued)

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

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

CONDUCTORS			Voltage	LINE COST				Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Total (o)	No.
								1
								2
								3
								4
								5
								6
								7
								8
								9
								10
								11
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								43
								44

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/2003	Year of Report Dec. 31, 2002

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	"	46.00	12.50	
4	"	"	138.00	12.50	
5	American Falls PP - attended	transmission	138.00	13.80	
6	American Falls	"	138.00	46.00	13.80
7	Artesian	distribution	46.00	13.00	
8	Bannock Creek	"	46.00	12.50	
9	Bethel Court	"	69.00	13.00	
10	Black Cat	"	138.00	13.09	
11	Blackfoot	"	46.00	12.50	
12	"	"	138.00	38.00	13.80
13	Bliss - attended	transmission	138.00	13.80	
14	Blue Gulch	distribution	138.00	34.50	
15	Boise Bench - attended	distribution	138.00	34.50	
16	"	transmission	138.00	69.00	13.80
17	"	"	230.00	138.00	13.80
18	Boise Cascade Emmett CSPP	distribution	69.00	13.00	
19	Boise Cascade 1	"	69.00	13.00	
20	Boise	"	138.00	13.00	
21	Borah	transmission	345.00	138.00	13.80
22	Bowmont	distribution	38.00	7.20	
23	"	"	138.00	34.50	
24	"	"	138.00	69.00	13.80
25	Brady	transmission	46.00	12.50	
26	"	"	230.00	138.00	13.80
27	Brownlee - attended	transmission	230.00	13.80	
28	Bruneau Bridge	distribution	138.00	34.50	
29	Buckhorn	"	69.00	38.00	
30	Bucyrus	"	46.00	7.20	
31	Buhl	"	46.00	13.00	
32	Burley Rural	"	69.00	13.00	
33	Butler	"	138.00	13.00	
34	Caldwell	"	138.00	13.00	
35	"	"	138.00	69.00	13.00
36	"	transmission	230.00	138.00	12.50
37	Canyon Creek	distribution	138.00	34.50	
38	"	"	138.00	69.00	12.50
39	Cascade Power Plant - attended	Transmission	69.00	4.60	
40	Chestnut	distribution	138.00	13.00	

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Clear Lake - attended	transmission	46.00	2.30	
2	Cliff	"	69.00	38.00	12.50
3	Cloverdale	Transmission	138.00	13.00	
4	"	"	138.00	69.00	12.50
5	Dale	Distribution	69.00	13.00	
6	"	"	138.00	34.50	
7	"	"	138.00	46.00	12.50
8	Danskin	Transmission	138.00	12.00	
9	Don	Distribution	138.00	7.60	
10	"	"	138.00	7.60	
11	"	"	138.00	13.80	7.20
12	"	"	138.00	13.80	
13	DRAM	"	138.00	13.00	
14	"	"	230.00	138.00	13.80
15	Duffin	"	138.00	34.50	
16	Eagle	"	138.00	13.00	
17	Eastgate	"	138.00	13.00	
18	Eden	"	138.00	34.50	
19	"	"	138.00	46.00	12.50
20	Elkhorn	distribution	138.00	12.00	
21	Elmore	Transmission	138.00	34.50	
22	"	"	138.00	69.00	12.50
23	Emmett	distribution	138.00	12.50	
24	"	"	138.00	69.00	12.50
25	Falls	"	46.00	12.50	
26	Filer	"	46.00	12.50	
27	Flying H	"	69.00	2.40	
28	Fort Hall	"	46.00	12.50	
29	Fossil Gulch	"	138.00	13.80	4.60
30	"	"	138.00	34.50	
31	Fremont	transmission	69.00	38.00	12.50
32	Gary	distribution	138.00	13.00	
33	Gem	distribution	69.00	13.00	
34	Golden Valley	"	69.00	12.50	
35	Gowen Substation	"	138.00	36.00	
36	Grindstone	"	35.00	12.50	
37	Grove	"	138.00	12.50	
38	Hagerman	"	46.00	12.50	
39	Hailey	"	138.00	12.50	
40	Haven	"	46.00	34.50	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Hewlett Packard	Distribution	138.00	13.10	
2	Hidden Springs	"	138.00	13.09	
3	Highland	"	138.00	13.09	
4	Hill	"	138.00	12.50	
5	Homedale	"	69.00	12.50	
6	Horseshoe Bend	Distribution	35.00	12.50	
7	"	"	69.00	12.50	
8	"	"	69.00	25.00	
9	Houston	"	69.00	13.00	
10	Hulen	distribution	46.00	13.00	
11	Hunt	transmission	230.00	138.00	13.80
12	Hydra	distribution	138.00	34.50	
13	Island	"	69.00	12.50	
14	Jerome	"	46.00	12.50	
15	"	"	138.00	12.50	
16	Julion Clawson	"	138.00	34.50	
17	Joplin	"	138.00	13.00	
18	Karcher	"	138.00	13.09	
19	Kenyon	"	69.00	12.50	
20	Ketchum	"	138.00	12.50	
21	Kinport	transmission	161.00	46.00	13.00
22	"	"	230.00	138.00	12.50
23	"	"	230.00	138.00	13.80
24	"	"	345.00	230.00	13.80
25	Kramer	distribution	138.00	34.50	
26	"	"	138.00	13.00	
27	Lamb	distribution	138.00	13.09	
28	Lansing	"	69.00	13.00	
29	Linden	"	138.00	13.00	
30	Locust	"	138.00	34.50	
31	"	transmission	230.00	138.00	13.00
32	Lower Malad - attended	transmission	138.00	7.20	
33	Lower Salmon - attended	"	138.00	13.80	
34	Map Rock	distribution	69.00	12.50	
35	McCall	"	69.00	12.50	
36	"	"	138.00	35.00	
37	"	"	138.00	69.00	12.50
38	Meridian	"	138.00	13.00	
39	Micron	"	138.00	12.50	
40	Midpoint	transmission	230.00	138.00	12.50

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Midpoint	Transmission	345.00	230.00	13.80
2	"	"	500.00	345.00	
3	Milner	distribution	69.00	38.00	13.80
4	"	"	69.00	38.00	7.20
5	"	"	138.00	34.50	
6	Milner PP - attended	transmission	138.00	13.80	
7	Moonstone	distribution	138.00	34.50	
8	Mora	"	138.00	34.50	
9	Moreland	"	46.00	12.50	
10	"	"	46.00	34.50	12.50
11	Mountain Home	Distribution	69.00	12.50	
12	Mountain Home Air Force Base	"	69.00	12.50	
13	"	"	138.00	12.50	
14	Nampa	"	69.00	12.50	
15	"	"	138.00	12.50	
16	"	"	138.00	69.00	12.50
17	New Meadows	distribution	69.00	35.00	
18	New Plymouth	"	69.00	12.50	
19	Parma	"	69.00	12.50	
20	"	"	69.00	34.50	
21	Paul	"	138.00	34.50	12.50
22	Payette	"	138.00	12.50	
23	Pingree	"	138.00	46.00	12.50
24	"	"	138.00	36.00	
25	Pleasant Valley	"	138.00	34.50	
26	Pocatello	"	46.00	12.50	
27	Portneuf	"	138.00	36.20	
28	Rockford	"	46.00	12.50	
29	Russett	"	138.00	12.50	
30	Sailor Creek	"	138.00	13.80	4.60
31	"	"	138.00	34.50	
32	Salmon	"	69.00	12.50	
33	"	"	69.00	34.50	12.50
34	Shoshone	"	46.00	13.00	
35	"	"	46.00	7.20	
36	Shoshone Falls - attached	transmission	46.00	2.30	
37	"	"	46.00	6.60	
38	Silver	distribution	138.00	34.50	
39	Simplot	distribution	138.00	12.50	
40	Sinker Creek	"	138.00	34.50	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/30/2003	Dec. 31, 2002

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Siphon	Distribution	138.00	34.50	
2	South Park	"	46.00	13.00	
3	State	"	69.00	12.50	
4	Stoddard	"	138.00	13.00	
5	Strike Power Plant - attended	transmission	138.00	13.80	
6	Sugar	distribution	138.00	34.50	
7	Swan Falls - attended	Transmission	138.00	6.90	
8	Taber	distribution	46.00	12.50	
9	Terry	"	138.00	12.50	
10	Thousand Springs - attended	transmission	46.00	6.90	
11	"	"	69.00	46.00	2.30
12	Toponis	distribution	138.00	34.50	
13	Twin Falls	"	138.00	13.00	
14	"	"	138.00	46.00	12.50
15	Twin Falls PP - attended	transmission	138.00	7.20	
16	"	"	138.00	13.20	
17	Upper Malad - attended	"	46.00	7.20	
18	Upper Salmon- attended	"	138.00	7.20	
19	Ustick	distribution	138.00	12.50	
20	Victory	"	138.00	12.50	
21	Ware	"	69.00	12.50	
22	Weiser	"	69.00	12.50	
23	"	"	138.00	69.00	12.50
24	Wye	distribution	69.00	12.50	
25	Zilog	"	69.00	12.50	
26					
27					
28	The above are all State of Idaho				
29					
30	Montana:				
31	Peterson	transmission	138.00	38.00	12.50
32					
33	Nevada:				
34	Valmy - attended	transmission	345.00	21.30	
35	Wells	"	138.00	69.00	12.50
36					
37	Oregon:				
38	Boardman - attended	transmission	500.00	24.00	
39	Cairo	distribution	69.00	12.50	
40	Hells Canyon - attended	transmission	230.00	13.80	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Hines	Transmission	138.00	115.00	12.50
2	Malheur Butte	distribution	69.00	34.50	12.50
3	Nyssa	"	69.00	12.50	
4	Ontario	"	138.00	12.50	
5	"	"	138.00	69.00	12.50
6	"	"	230.00	138.00	12.50
7	Ore-Ida	distribution	69.00	12.50	
8	Oxbow - attended	transmission	69.00	38.00	12.50
9	"	"	230.00	13.80	
10	Oxbow Attended	transmission	230.00	138.00	13.80
11	Quartz	transmission	138.00	69.00	12.50
12	"	"	138.00	80.00	12.50
13	Vale	distribution	69.00	13.09	
14					
15	Wyoming:				
16	Jim Bridger - attended	transmission	345.00	22.00	
17					
18					
19					
20					
21					
22					
23	Transformers-distribution substations under 10,000				
24	KVA 85 unattended.				
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/2003	Year of Report Dec. 31, 2002

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
300	2					1
20	2					2
15	1					3
18	1					4
72	1					5
25	1					6
10	1					7
10	1					8
12	1					9
15	1					10
30	2					11
130	3	1				12
69	3					13
15	1					14
48	2					15
90	4					16
398	4					17
12	1					18
10	1					19
67	3					20
450	3	1				21
8	3					22
18	1					23
25	1					24
		6				25
300	3					26
734	5	1				27
30	2					28
20	1					29
13	4					30
20	2					31
12	1					32
48	2					33
32	2					34
50	2					35
240	2					36
15	1					37
8	1					38
12	1					39
48	2					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
4	1					1
25	3	1				2
48	2					3
50	2					4
		1				5
24	1					6
25	1					7
96	2					8
172	12	1				9
54	3					10
15	1					11
26	1					12
101	6					13
160	2					14
36	2					15
35	2					16
36	2					17
24	1					18
15	1					19
15	2					20
16	1					21
30	2					22
15	1					23
25	1					24
17	2					25
10	1					26
15	2					27
10	1					28
8	1					29
15	1					30
50	3	1				31
20	1					32
17	2					33
10	1	1				34
18	1					35
10	2					36
48	2	1				37
12	2					38
20	1					39
12	1					40

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
20	1					1
8	1					2
18	1					3
24	1					4
15	2					5
6	1					6
12	1					7
5	1					8
10	1					9
10	1					10
300	3					11
24	1					12
12	1					13
10		1				14
20	1					15
30	2					16
15	1					17
12	1					18
20	2					19
42	2					20
		8				21
180	1					22
180	1					23
600	3					24
12	1					25
18	1					26
15	1					27
12	1					28
33	2					29
48	2					30
180	1					31
15	1					32
70	4					33
10	1					34
8	1					35
18	1					36
30	1					37
36	2					38
48	4					39
120	1					40

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
720	2					1
1000	4					2
75	3	1				3
8	3	1				4
16	1					5
36	1					6
12	1					7
33	2					8
8	1					9
10	3	1				10
12	1					11
		1				12
18	1					13
		1				14
42	2					15
25	1					16
10	4					17
10	1					18
10	1					19
12	1					20
36	2					21
22	3					22
50	3					23
22	2					24
42	2					25
36	2					26
18	1					27
14	2					28
18	1					29
15	2					30
15	1					31
10	1	4				32
10	3	1				33
1						34
1	1					35
3	1					36
10	1					37
12	1					38
15	1					39
12	1					40

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/30/2003	Year of Report Dec. 31, 2002

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
33	2					1
10	1					2
33	2					3
15	1					4
83	3					5
10	1					6
18	1					7
5	1					8
42	3					9
8	1					10
5	3					11
18	1					12
40	2					13
23	2					14
9	1					15
72	1					16
8	1					17
36	4					18
44	2					19
24	1					20
10	1					21
20	2					22
25	1					23
51	3					24
25	2					25
						26
						27
						28
						29
						30
30	3	1				31
						32
						33
150	1					34
26	4					35
						36
						37
55	1					38
12	1					39
500	3	1				40

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
40	1					1
10	3					2
20	2					3
38	2					4
55	3					5
240	2					6
15	1					7
10	3	1				8
244	2					9
100	1					10
30	2					11
133	4					12
10	1					13
						14
						15
748	1					16
						17
						18
						19
						20
						21
						22
						23
						24
						25
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Schedule	Page No.

Schedule | Page No.

ANNUAL REPORT

IDAHO SUPPLEMENT TO FERC FORM 1

MULTI-STATE ELECTRIC COMPANIES

INDEX

STATEMENT OF INCOME FOR THE YEAR

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

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	11	$ 812,863,190	$ 841,902,029
3	Operating Expenses			
4	Operation Expenses (401)	15	518,963,603	600,260,172
5	Maintenance Expenses (402)	15	49,850,797	50,747,414
6	Depreciation Expense (403)		77,444,065	73,251,218
7	Amort. & Depl. of Utility Plant (404-405)		7,626,461	5,745,196
8	Amort. of Utility Plant Acq. Adj. (406)			
9	Amort. of Property Losses, Unrecovered Plant and Regulatory Study Costs (407)			
10	Amort. of Conversion Expenses (407)			
11	Regulatory Debits (407.3)			
12	(Less) Regulatory Credits (407.4)			
13	Taxes Other Than Income Taxes (408.1)	2	17,761,053	17,485,363
14	Income Taxes - Federal (409.1)	2	90,125,353	(76,740,642)
15	- Other (409.1)	2	11,662,062	(21,117,310)
16	Provision for Deferred Income Taxes (410.1 & 411.1) Net	2	(104,770,411)	114,610,737
18	Investment Tax Credit Adj. - Net (411.4)	2	(547,120)	2,867,361
19	(Less) Gains from Disp. of Utility Plant (411.6)			
20	Losses from Disp. of Utility Plant (411.7)			
21	(Less) Gains from Disposition of Allowances (411.8)			
22	Losses from Disposition of Allowances (411.9)			
23	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 22)		668,115,863	767,109,510
24	Net Utility Operating Income (Enter Total of line 2 less 23) (Carry forward to page 11, line 27)		$ 144,747,327	$ 74,792,519

TAXES ALLOCATED TO IDAHO

Kind of Tax	Taxes Charged During Year
Taxes Other Than Income Taxes:	
Labor Related:	
FICA	$ 7,605,090
FUTA	94,241
State Unemployment	182,605
Payroll Deduction & Loading	(7,838,260)
Total Labor Related	43,676
Property Taxes	14,695,239
Kilowatt-hour Tax	1,096,308
Licenses	2,855
Regulatory Commission Fees	1,714,256
Irrigation PIC	208,718
Total Taxes Other Than Income Taxes	17,761,053
Federal Income Taxes	90,125,353
State Income Taxes	11,662,062
Deferred Income Taxes	(104,770,411)
Investment Tax Credit Adjustment - Net	(547,120)
Total Taxes Allocated to Idaho	$ 14,230,936

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)	$ 9,761,917	$ 12,637,655
2	Customer Accounts Receivable (Account 142)	58,702,410	56,947,245
3	Other Accounts Receivable (Account 143)	2,259,483	2,694,113
4	(Disclose any capital stock subscription received)		
5	Total	70,723,810	72,279,013
6			
7	Less: Accumulated Provision for Uncollectible		
8	Accounts-Cr. (Account 144)	1,500,000	1,566,346
9			
10	Total, Less Accumulated Provision for		
11	Uncollectible Accounts	$ 69,223,810	$ 70,712,667
12			
13			
14	Notes Receivable - Account 141: (at 12-31-02)		
15	Directors, officers, and employees - $ 7,855,081		
16			
17			
18	Other Accounts Receivable - Account 143: (at 12-31-02)		
19	Directors, officers, and employees - $ (71)		
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	$ 1,397,455	-	-	$ 102,545	$ 1,500,000
23	Prov. for uncollectibles					
24	for year	66,346				66,346
25	Accounts written off					
26	Coll. of accounts					
27	written off					
28	Adjustments (explain)					
29						
30						
31						
32	Balance end of year	$ 1,463,801	$ -	$ -	$ 102,545	$ 1,566,346
33						

RECEIVABLES FROM ASSOCIATED COMPANIES (Accounts 145, 146)

1. Report particulars of notes and accounts receivable from associated companies at end of year.
2. Provide separate headings and totals for accounts 145, Notes Receivable from Associated Companies, and 146, Accounts Receivable from Associated Companies, in addition to a total for the combined accounts.
3. For notes receivable list each note separately and state purpose for which received. Show also in column (a) date of note, date of maturity and interest rate.
4. If any note was received in satisfaction of an open account, state the period covered by such open account.
5. Include in column (f) interest recorded as income during the year, including interest on accounts and notes held at any time during the year.
6. Give particulars of any notes pledged or discounted, also of any collateral held as guarantee of payment of any note or account.

Line No.	Particulars (a)	Balance Beginning of Year (b)	Totals for Year: Debits (c)	Totals for Year: Credits (d)	Balance End of Year (e)	Interest For Year (f)
1	Account 145:					
2						
3	Idacorp	$ 33,686,906	$ 8,463,709	$ 20,322,893	$ 21,827,722	
4						
5						
6						
7						
8						
9						
10						
11						
12	Account 146:					
13						
14						
15	IDACORP Energy	$ 2,962,526.00	21,870,556	$ 20,573,069	$ 4,260,013	
16						
17	IDACORP Financial Services	6,281		6,281		
18						
19	Ida-West Energy					
20	Company	9,167			9,167	
21						
22						
23						
24						
25	Rocky Mountain Communication	299,480	1,883,775	899,879	1,283,376	
26						
27	IDACORP, Inc	287,911	1,656,507	1,762,916	181,502	
28						
29	IDACORP Energy Solutions	264,933	78,143		343,076	
30						
31	Total Account 146	$ 3,830,298	$ 25,410,838	$ 23,242,145	$ 6,077,134	
32						

STATE OF IDAHO - TOTAL SYSTEM DATA

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

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

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

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

Line No.	Description of Property (a)	Original Cost of Related Property (b)	Date Journal Entry Approved (When Required) (c)	Acct 421.1 (d)	Acct 421.2 (e)
1	Gain on disposition of				
2	property:				
3					
4	State Street Office Sale	$ 346,000		$ 345,995	
5					
6					
7					
8					
9					
10					
11					
12	Miscellaneous items (3)	363		(16,820)	
13					
14	Total gain	$ 346,363		$ 329,175	
15					
16	Loss on disposition of				
17	property: (3 items)	$ 66,034			$ 2,678
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31	Total loss	$ 66,034			$ 2,678

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	ANDERSON PERRY & ASSOCIATES	Legal Services	$ 16,347
2	BARKER, ROSHOLT & SIMPSON LLP	Legal Services	165,866
3	BIDART & ROSS INC	Management Services	58,914
4	BLACKBURN & JONES	Management Services	141,661
5	BLACKFIN TECHNOLOGY INC	Management Services	36,000
6	BLANK & ASSOCIATES	Management Services	80,019
7	BLUE HERON CONSULTING INC	Programming Services	46,724
8	BOESCH & COMPANY	Govermental Relations Counsel	15,000
9	BRENNEMAN, JOHN	Govermental Relations Counsel	63,372
10	BUFFINGTON, JOHN M	Geomorphology Report	12,950
11	BURKE CSA	Customer Survery Services	176,228
12	BUSINESS LEGAL CONSULTING	Legal Services	27,233
13	CAMBRIDGE ENERGY RESEARCH	Management Services	32,300
14	CENTER FOR WATER RESEARCH	Environmental Services	159,655
15	CH2M HILL	Management Services	36,018
16	CHARLES RIVER ASSOCIATES INCORP	Management Services	223,876
17	CHAVEZ WRITING & EDITING	Data Processing Services	89,239
18	CHRISTOPHER F HOPPER	Legal Services	88,862
19	CHURCH, JOHN S	Economic analysis Services	72,000
20	CONNOLLY & SMYSER CHTD	Management Services	18,180
21	CORNERSTONE SYSTEMS INC	Programming Services	1,147,500
22	DAVID EVANS AND ASSOCIATES	Management Services	36,549
23	DAVIS WRIGHT TREMAINE LLP	Legal Services	255,237
24	DELOITTE & TOUCHE LLP	Accounting Services	668,152
25	DRI-WEFA	Management Services	21,000
26	DUNNE, THOMAS	Geomorphology Report	10,800
27	EAMES, MATT C	Management Services	21,454
28	ECOS CONSULTING	Management Services	66,042
29	EOP GROUP	Management Services	82,347
30	EVANS KEANE	Management Services	48,859
31	FISHPRO	Environmental Services	50,069
32	FRAMATOME AND DE&S, INC	Management Services	112,795
33	GENERAL RELIABILITY	Management Services	75,000
34	HALL FARLEY OBERRECHT & B	Legal Services	45,633
35	HDR ENGINEERING, INC	Engineering Services	190,790
36	HERNDON, STEVEN L	Relicensing Services	49,000
37	HOLLAND CONSULTING GROUP	Management Services	19,711
38	J D POWER AND ASSOCIATES	Management Services	30,000
39	JBR ENVIRONMENTAL CONSULTANTS	Environmental Services	17,804
40	KNOWBLAUCH, WAYNE A	Management Services	19,026
41	LE BOEUF LAMB GREENE	Management Services	1,249,187
42	LITCHFIELD CONSULTING GROUP	Management Services	29,738
43	MARSH USA INC	Management Services	13,000
44	MCFAIN & ASSOC RESEARCH INC	Customer Survery Services	32,762
45	MILLER BATEMAN LLP	Legal Services	167,073
46	NAVIGANT CONSULTING, INC	Management Services	11,000
47	NIELSEN GROUP INC	Customer Load Survey	308,681
48	PB POWER	Engineering Services	24,817
49	PEGASUS HEALTHCARE TECHNOLOGY	Management Services	10,350

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	PERKINS COIE LLP	Legal Services	$ 13,460
2	POWER ENGINEERS	Engineering Services	142,642
3	RALSTON & ASSOCIATES	Engineering Services	17,837
4	RIDDELL WILLIAMS P.S.	Legal Services	61,000
5	RISK ADVISORY	Management Services	44,060
6	RIVERSIDE TECHNOLOGY	Environmental Services	19,142
7	SALLADAY & DAVIS	Environmental Services	26,685
8	SALLADAY, G LANCE	Legal Services	76,659
9	SCHWABE WILLIAMSON & WYATT	Management Services	55,424
10	SEAVISUAL CONSULTING	Management Services	43,019
11	SIDLEY AUSTIN BROWN AND WOOD	Management Services	176,021
12	SIMONS & ASSOCIATES INC	Management Services	66,458
13	SORENSEN CONSULTING SERVICES	Management Services	85,388
14	STEPTOE & JOHNSON LLP	Legal Services	1,311,211
15	STOEL RIVES LLP	Legal Services	25,570
16	STONEHART ASSOCIATES INC	Management Services	15,120
18	TETRA TECH EM INC	Environmental Services	382,885
19	U S GEOLOGICAL SURVEY	Environmental Studies	32,270
20	UTILITIES INTERNATIONAL	Management Services	30,406
21	UTILITY RESOURCES	Management Services	49,711
22	VAN NESS FELDMAN	Management Services	388,935
23	WEST CONSULTANTS	Engineering Services	42,403
24	YTURRI, ROSE, BURNHAM, BENTZ	Legal Services	20,978
25			
26			
27			
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PROFESSIONAL OR CONSULTATIVE SERVICES

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

PAYEE	PREDOMINANT NATURE OF SERVICE	AMOUNT
ATER, WYNNE LLP	MANAGEMENT SERVICES	$ 7,949
BLACK & VEATCH	MANAGEMENT SERVICES	9,464
DHI INC	ENVIRONMENTAL STUDIES	5,555
EVANS RANGE RECLAMATION	MANAGEMENT SERVICES	7,040
HAGEN DAVID	MANAGEMENT SERVICES	9,975
IBM	MANAGEMENT SERVICES	8,251
IVEY & BAUER	MANAGEMENT SERVICES	9,780
JONES CHARTERED	LEGAL SERVICES	5,775
SANDS ANDERSON MARKS & MILLER	LEGAL SERVICES	8,148
SHARP & SMITH	ENGINEERING SERVICES	7,544
STONE, R H	MANAGEMENT SERVICES	9,177
SUPER, ARLIN	MANAGEMENT SERVICES	9,375

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

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

Line No.	Account (a)	Balance at Beginning of year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	$ 5,161	
3	(302) Franchises and Consents	7,227,781	
4	(303) Miscellaneous Intangible Plant	47,864,471	
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	55,097,414	
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	TOTAL Steam Production Plant (Enter Total of lines 8 thru 14)	693,199,238	
16	B. Nuclear Production Plant		
17	(320) Land and Land Rights		
18	(321) Structures and Improvements		
19	(322) Reactor Plant Equipment		
20	(323) Turbogenerator Units		
21	(324) Accessory Electric Equipment		
22	(325) Misc. Power Plant Equipment		
23	TOTAL Nuclear Production Plant (Enter Total of lines 17 thru 22)		
24	C. Hydraulic Production Plant		
25	(330) Land and Land Rights		
26	(331) Structures and Improvements		
27	(332) Reservoirs, Dams, and Waterways		
28	(333) Water Wheels, Turbines, and Generators		
29	(334) Accessory Electric Equipment		
30	(335) Misc. Power Plant Equipment		
31	(336) Roads, Railroads, and Bridges		
32	TOTAL Hydraulic Production Plant (Enter Total of lines 25 thru 31)	567,549,422	
33	D. Other Production Plant		
34	(340) Land and Land Rights		
35	(341) Structures and Improvements		
36	(342) Fuel Holders, Products and Accessories		
37	(343) Prime Movers		
38	(344) Generators		
39	(345) Accessory Electric Equipment		

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

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

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

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			$ 13,412	(301)	2
			6,514,471	(302)	3
			54,318,994	(303)	4
			60,846,876		5
					6
					7
				(310)	8
				(311)	9
				(312)	10
				(313)	11
				(314)	12
				(315)	13
				(316)	14
			699,476,737		15
					16
				(320)	17
				(321)	18
				(322)	19
				(323)	20
				(324)	21
				(325)	22
					23
					24
				(330)	25
				(331)	26
				(332)	27
				(333)	28
				(334)	29
				(335)	30
				(336)	31
			571,810,235		32
					33
				(340)	34
				(341)	35
Information is available only on an end of year basis.				(342)	36
				(343)	37
				(344)	38
				(345)	39

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

Line No.	Account (a)	Balance at Beginning of year (b)	Additions (c)
40	(346) Misc. Power Plant Equipment		
41	TOTAL Other Production Plant (Enter Total of lines 34 thru 40)	$ 43,891,388	
42	TOTAL Production Plant (Enter Total of lines 15, 23, 32, and 41)	1,304,640,048	
43	3. TRANSMISSION PLANT		
44	(350) Land and Land Rights	11,439,654	
45	(352) Structures and Improvements	24,070,377	
46	(353) Station Equipment	152,434,562	
47	(354) Towers and Fixtures	45,883,182	
48	(355) Poles and Fixtures	64,895,165	
49	(356) Overhead Conductors and Devices	79,568,613	
50	(357) Underground Conduit		
51	(358) Underground Conductors and Devices		
52	(359) Roads and Trails	253,137	
53	TOTAL Transmission Plant (Enter Total of lines 44 thru 52)	378,544,689	
54	4. DISTRIBUTION PLANT		
55	(360) Land and Land Rights	3,238,044	
56	(361) Structures and Improvements	12,539,229	
57	(362) Station Equipment	96,441,563	
58	(363) Storage Battery Equipment		
59	(364) Poles, Towers, and Fixtures	151,630,460	
60	(365) Overhead Conductors and Devices	80,310,419	
61	(366) Underground Conduit	28,055,847	
62	(367) Underground Conductors and Devices	116,255,035	
63	(368) Line Transformers	225,942,526	
64	(369) Services	40,269,963	
65	(370) Meters	35,945,582	
66	(371) Installations on Customer Premises	1,850,356	
67	(372) Leased Property on Customer Premises		
68	(373) Street Lighting and Signal Systems	3,594,453	
69	TOTAL Distribution Plant (Enter Total of lines 55 thru 68)	796,073,478	
70	5. GENERAL PLANT		
71	(389) Land and Land Rights	7,919,696	
72	(390) Structures and Improvements	50,987,723	
73	(391) Office Furniture and Equipment	44,335,417	
74	(392) Transportation Equipment	33,720,020	
75	(393) Stores Equipment	798,029	
76	(394) Tools, Shop, and Garage Equipment	3,091,382	
77	(395) Laboratory Equipment	7,873,207	
78	(396) Power Operated Equipment	5,675,368	
79	(397) Communication Equipment	15,721,270	
80	(398) Miscellaneous Equipment	1,687,745	
81	SUBTOTAL (Enter Total of lines 71 thru 80)	171,809,857	
82	(399) Other Tangible Property		
83	TOTAL General Plant (Enter Total of lines 81 and 82)	171,809,857	
84	TOTAL (Accounts 101 and 106)	2,706,165,486	
85	(102) Electric Plant Purchased		
86	(Less) (102) Electric Plant Sold		
87	(103) Experimental Plant Unclassified		
88	TOTAL Electric Plant in Service	$ 2,706,165,486	

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)	40
			$ 46,391,611		41
			1,317,678,584		42
					43
			13,771,426	(350)	44
			22,798,079	(352)	45
			165,084,935	(353)	46
			47,394,555	(354)	47
			65,169,045	(355)	48
			83,033,641	(356)	49
				(357)	50
				(358)	51
			252,181	(359)	52
			397,503,863		53
					54
			2,807,735	(360)	55
			13,992,993	(361)	56
			112,946,325	(362)	57
				(363)	58
			158,178,712	(364)	59
			83,954,626	(365)	60
			31,032,480	(366)	61
			122,900,635	(367)	62
			231,845,484	(368)	63
			42,437,018	(369)	64
			36,941,798	(370)	65
			1,972,626	(371)	66
				(372)	67
			3,681,962	(373)	68
			842,692,395		69
					70
			7,758,870	(389)	71
			51,558,446	(390)	72
			45,495,614	(391)	73
			37,689,931	(392)	74
			917,267	(393)	75
			3,198,861	(394)	76
			7,915,997	(395)	77
			5,796,142	(396)	78
			17,625,587	(397)	79
			1,812,541	(398)	80
			179,769,256		81
				(399)	82
			179,769,256		83
			2,798,490,974		84
				(102)	85
					86
				(103)	87
			$ 2,798,490,974		88

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	$ 296,274,337	$ 250,774,139
3	(442) Commercial and Industrial Sales		
4	Small (or Commercial)(See Instr. 4) (1)	277,574,779	224,852,716
5	Large (or Industrial)(See Instr. 4) (2)	169,021,742	146,522,467
6	Non-Juristictional Sales - Embarcadero - (allocated)	-	-
7	(444) Public Street and Highway Lighting	2,636,203	2,299,433
8	(445) Other Sales to Public Authorities		
9	(446) Sales to Railroads and Railways		
10	(448) Interdepartmental Sales		
11	TOTAL Sales to Ultimate Consumers	745,507,061 *	624,448,755
12	(447) Sales for Resale - Opportunity....Non-Firm Only	37,425,361	185,532,680
13	TOTAL Sales of Electricity	782,932,422	809,981,435
14	(449.1) Provision for Rate Refunds		1,823,627
15	TOTAL Revenue Net of Provision for Refunds	782,932,422	811,805,062
16	**Other Operating Revenues**		
17	(450) Forfeited Discounts		
18	(451) Miscellaneous Service Revenues	3,328,243	3,237,418
19	(453) Sales of Water and Water Power		
20	(454) Rent from Electric Property	16,892,664	15,739,389
21	(455) Interdepartmental Rents		
22	(456) Other Electric Revenues	9,709,860	11,120,160
23			
24			
25			
26	TOTAL Other Operating Revenues	29,930,768	30,096,967
27	TOTAL Electric Operating Revenues	$ 812,863,190	$ 841,902,029

(1) Commercial and Industrial sales - Small - under 1,000 KW and includes all irrigation customers.
(2) Commercial and Industrial sales - Large - 1,000 KW and over.

ELECTRIC OPERATING REVENUES (Account 400) (Continued)

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

KILOWATT HOURS SOLD		AVERAGE NUMBER OF CUSTOMERS PER MONTH		
Amount for Current Year (d)	Amount for Previous Year (e)	Amount for Current Year (f)	Number for Previous Year (g)	Line No.
				1
4,197,803,194	4,117,127,872	326,788	318,076	2
				3
5,057,033,033	4,581,583,827	63,167	62,178	4
2,982,938,946	3,666,993,888	107	107	5
				6
27,574,180	26,208,245	306	232	7
				8
				9
				10
12,265,349,353 **	12,391,913,832	390,368	380,593	11
1,891,233,207	1,601,490,547	N/A	N/A	12
14,156,582,560	13,993,404,379	390,368	380,593	13
				14

* Includes $ (1,676,699) unbilled revenues.

** Includes (18,187,010) KWH relating to unbilled revenues.

lines 6, 12 & 17 through 27 are on an "allocated" basis.

STATE OF IDAHO - ALLOCATED

Idaho Power Company	An Original ELECTRIC OPERATION AND MAINTENANCE EXPENSES	December 31, 2002

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	$ 931,752	$ 962,083
5	(501) Fuel	89,913,734	86,821,776
6	(502) Steam Expenses	3,435,969	5,016,622
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr		
9	(505) Electric Expenses	953,923	1,320,464
10	(506) Miscellaneous Steam Power Expenses	3,501,977	5,055,445
11	(507) Rents	673,413	574,072
12	(509) Allowances		
13	TOTAL Operation (Enter Total of lines 4 thru 12)	99,410,767	99,750,463
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	1,705,629	1,713,789
16	(511) Maintenance of Structures	140,642	153,801
17	(512) Maintenance of Boiler Plant	7,740,357	7,966,872
18	(513) Maintenance of Electric Plant	2,570,012	3,156,857
19	(514) Maintenance of Miscellaneous Steam Plant	8,154,693	7,376,324
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	20,311,334	20,367,643
21	TOTAL Power Production Expenses-Steam Power (Enter Total of lines 13 and 20)	119,722,101	120,118,106
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	3,805,639	3,088,060
45	(536) Water for Power	2,782,243	2,937,511
46	(537) Hydraulic Expenses	4,548,402	4,127,831
47	(538) Electric Expenses	867,914	1,169,395
48	(539) Miscellaneous Hydraulic Power Generation Expenses	1,542,909	1,577,869
49	(540) Rents	352,547	277,935
50	TOTAL Operation (Enter Total of lines 44 thru 49)	13,899,654	13,178,600

Idaho Power Company	An Original ELECTRIC OPERATION AND MAINTENANCE EXPENSES	December 31, 2002

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	$ 914,638	$ 990,161
54	(542) Maintenance of Structures	1,160,952	925,409
55	(543) Maintenance of Reservoirs, Dams, and Waterways	678,515	461,418
56	(544) Maintenance of Electric Plant	1,965,955	1,872,587
57	(545) Maintenance of Miscellaneous Hydraulic Plant	2,043,284	1,951,706
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	6,763,345	6,201,282
59	TOTAL Power Production Expenses-Hydraulic Power (Enter Total of lines 50 and 58)	20,662,999	19,379,883
61	Operation		
62	(546) Operation Supervision and Engineering	286,681	154,725
63	(547) Fuel	4,136,220	2,682,961
64	(548) Generation Expenses	298,740	459,322
65	(549) Miscellaneous Other Power Generation Expenses	372,857	298,907
66	(550) Rents	16,886	4,705,353
67	TOTAL Operation (Enter Total of lines 62 thru 66)	5,111,384	8,301,268
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	858	50
70	(552) Maintenance of Structures	149,970	13,309
71	(553) Maintenance of Generating and Electric Plant	203,886	237,678
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	323,097	-
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	677,810	251,038
74	TOTAL Power Production Expenses-Other Power (Enter Total of lines 67 and 73)	5,789,194	8,552,306
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	129,931,369	531,853,029
77	(556) System Control and Load Dispatching	10,132	680,970
78	(557) Other Expenses	159,420,867	(159,438,637)
79	TOTAL Other Power Supply Expenses (Enter Total of lines 76 thru 78)	289,362,368	373,095,362
80	TOTAL Power Production Expenses (Enter Total of lines 21, 41, 59, 74, and 79)	435,536,662	521,145,657
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	1,453,115	1,605,476
84	(561) Load Dispatching	2,008,771	1,986,221
85	(562) Station Expenses	1,512,121	1,029,866
86	(563) Overhead Line Expenses	463,498	448,094
87	(564) Underground Line Expenses		
88	(565) Transmission of Electricity by Others	2,023,634	1,385,516
89	(566) Miscellaneous Transmission Expenses	344,344	358,250
90	(567) Rents	1,349,887	1,089,015
91	TOTAL Operation (Enter Total of lines 83 thru 90)	9,155,371	7,902,438
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	634,608	690,097
94	(569) Maintenance of Structures	47,536	217
95	(570) Maintenance of Station Equipment	1,190,788	2,598,007
96	(571) Maintenance of Overhead Lines	1,867,621	2,014,639
97	(572) Maintenance of Underground Lines		
98	(573) Maintenance of Miscellaneous Transmission Plant	7,665	11,023
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	3,748,218	5,313,982
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	12,903,589	13,216,420
102	Operation		
103	(580) Operation Supervision and Engineering	3,139,063	3,151,571

Idaho Power Company	An Original ELECTRIC OPERATION AND MAINTENANCE EXPENSES	December 31, 2002

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	$ 2,224,209	$ 2,475,593
106	(582) Station Expenses	1,295,166	1,270,672
107	(583) Overhead Line Expenses	3,306,712	3,466,781
108	(584) Underground Line Expenses	2,303,426	2,484,836
109	(585) Street Lighting and Signal System Expenses	351,814	351,356
110	(586) Meter Expenses	5,778,095	4,500,318
111	(587) Customer Installations Expenses	437,777	466,219
112	(588) Miscellaneous Distribution Expenses	3,416,166	3,460,708
113	(589) Rents	158,518	155,153
114	TOTAL Operation (Enter Total of lines 103 thru 113)	22,410,947	21,783,206
115	Maintenance		
116	(590) Maintenance Supervision and Engineering	60,438	83,230
117	(591) Maintenance of Structures	5,649	2,037
118	(592) Maintenance of Station Equipment	2,485,110	2,625,142
119	(593) Maintenance of Overhead Lines	10,046,558	9,978,029
120	(594) Maintenance of Underground Lines	1,155,509	1,351,967
121	(595) Maintenance of Line Transformers	1,279,428	1,515,358
122	(596) Maintenance of Street Lighting and Signal Systems	259,068	62,625
123	(597) Maintenance of Meters	1,418,499	1,651,978
124	(598) Maintenance of Miscellaneous Distribution Plant	150,887	194,582
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	16,861,146	17,464,949
126	TOTAL Distribution Expenses (Enter Total of lines 114 and 125)	39,272,092	39,248,156
127	4. CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision	392,987	583,674
130	(902) Meter Reading Expenses	4,131,419	4,073,822
131	(903) Customer Records and Collection Expenses	6,581,296	8,537,156
132	(904) Uncollectible Accounts	4,576,002	3,307,248
133	(905) Miscellaneous Customer Accounts Expenses	2,164	2,214
134	TOTAL Customer Accounts Expenses (Enter Total of lines 129 thru 133)	15,683,869	16,504,114
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision	240,026	145,764
138	(908) Customer Assistance Expenses	7,085,731	7,502,692
139	(909) Informational and Instructional Expenses	24	17,443
140	(910) Miscellaneous Customer Service and Informational Expenses	440,365	267,645
141	TOTAL Cust. Service and Informational Expenses (Enter Total of lines 137 thru 140)	7,766,146	7,933,543
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	26,926,665	30,955,226
152	(921) Office Supplies and Expenses	15,743,120	14,220,216
153	(Less) (922) Administrative Expenses Transferred-Credit	(17,395,007)	(17,247,920)

STATE OF IDAHO - ALLOCATED

Idaho Power Company	An Original ELECTRIC OPERATION AND MAINTENANCE EXPENSES	December 31, 2002

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	$ 4,205,465	$ 4,630,771
156	(924) Property Insurance	2,599,148	2,030,349
157	(925) Injuries and Damages	2,538,237	2,710,188
158	(926) Employee Pensions and Benefits	17,026,486	9,714,635
159	(927) Franchise Requirements	1,750	1,575
160	(928) Regulatory Commission Expenses	2,752,148	2,704,160
161	(929) Duplicate Charges-Cr		
162	(930.1) General Advertising Expenses	530,714	767,691
163	(930.2) Miscellaneous General Expenses	1,208,838	1,295,063
164	(931) Rents	25,533	29,226
165	TOTAL Operation (Enter Total of lines 151 thru 164)	56,163,097	51,811,179
166	Maintenance		
167	(935) Maintenance of General Plant	1,488,945	1,148,519
168	TOTAL Administrative and General Expenses (Enter Total of lines 165 thru 167)	57,652,042	52,959,698
169	TOTAL Electric Operation and Maintenance Expenses (Enter Total of lines 80, 100, 126, 134, 141, 148, and 168)	$ 568,814,400	$ 651,007,587

IDAHO ONLY

NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES

1. The data on number of employees should be reported for the payroll period ending nearest to October 31, or any payroll period ending 60 days before or after October 31.

2. If the respondent's payroll for the reporting period includes any special construction personnel, include such employees on line 3, and show the number of such special construction employees in a footnote.

3. The number of employees assignable to the electric department from joint functions of combination utilities may be determined by estimate, on the basis of employee equivalents. Show the estimated number of equivalent employees attributed to the electric department from joint functions.

1	Payroll Period Ended (Date)	December 31, 2002
2	Total Regular Full-Time Employees	1,653
3	Total Part-Time and Temporary Employees	34
4	Total Employees	1,687