e-FILING REPORT COVER SHEET

REPORT NAME: FERC Form 1 Annual Report

COMPANY NAME: Idaho Power Company

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☒ No ☐ Yes

If yes, please submit only the cover letter electronically. Submit confidential information as directed OAR 860-001-0070 or the terms of an applicable protective order.

If known, please select designation: ☒ RE (Electric) ☐ RG (Gas) ☐ RW (Water)
☐ RO (Other)

Report is required by: ☒ OAR 860-027-0070
☐ Statute
☐ Order
☐ Other

Is this report associated with a specific docket/case? ☒ No ☐ Yes

If Yes, enter docket number:

Key words:

If known, please select the PUC Section to which the report should be directed:

☐ Corporate Analysis and Water Regulation

☐ Economic and Policy Analysis

☐ Electric and Natural Gas Revenue Requirements

☐ Electric Rates and Planning

☐ Natural Gas Rates and Planning

☐ Utility Safety, Reliability & Security

☐ Administrative Hearings Division

☐ Consumer Services Section

PLEASE NOTE: Do NOT use this form or e-filing with the PUC Filing Center for:

- **Annual Fee Statement form and payment remittance or**
- **OUS or RSPF Surcharge form or surcharge remittance or**
- **Any other Telecommunications Reporting or**
- **Any daily safety or safety incident reports or**
- **Accident reports required by ORS 654.715.**

LISA D. NORDSTROM
Lead Counsel
lnordstrom@idahopower.com

June 22, 2012

Attention: Filing Center
Public Utility Commission of Oregon
550 Capitol Street NE, Suite 215
P. O. Box 2148
Salem, OR 97308-2148

Re: Idaho Power Company's Annual FERC Form 1 Report

Dear Sir or Madam:

Idaho Power Company herewith transmits for electronic filing its FERC Form 1 report for the year ended December 31, 2011, previously mailed in hard copy to Judy Johnson, Program Manager of Revenue Requirements, on April 13, 2012. Idaho Power is filing this report again, but in electronic format, per the notice received from the Commission dated June 18, 2012.

If you have any questions, please call me at 208-388-5825.

Very truly yours,

Lisa D. Nordstrom

Lisa D. Nordstrom

LDN:kkt
Enclosures

IDAHO POWER®
An IDACORP Company

April 13, 2012

Ms. Judy Johnson
Utility Program
Oregon Public Utility Commission
550 Capitol Street N.E.
Salem, OR 97310-1380

Dear Ms. Johnson:

Enclosed is an original and one copy of Idaho Power Company's Annual Report to the Commission for the year ended December 31, 2011 composed of FERC Form 1 and an "Oregon Supplement Section" containing Oregon statistics. There are also enclosed two copies of IDACORP, Inc.'s Annual Report to Shareowners which includes the SEC Form 10-K. Each year a copy of the EIA-860 is also included, however, at this time there is no indication when the report will be available.

Yours very truly,

Ken Petersen
Corporate Controller
and Chief Accounting Officer

KP:db
Enclosure

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

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

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2014)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2014)
Form 3-Q Approved
OMB No.1902-0205
(Expires 05/31/2014)

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

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

Exact Legal Name of Respondent (Company)	Year/Period of Report
Idaho Power Company	End of 2011/Q4

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

IDENTIFICATION

01 Exact Legal Name of Respondent Idaho Power Company	02 Year/Period of Report End of 2011/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 1221 W Idaho St, P.O. Box 70 Boise, Id 83707-0070	
05 Name of Contact Person Ken Petersen	06 Title of Contact Person Coporate Controller and CAO
07 Address of Contact Person *(Street, City, State, Zip Code)* 1221 W Idaho St, 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) 388-2761	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name / 02 Title	03 Signature	04 Date Signed *(Mo, Da, Yr)*
01 Name: Ken Petersen 02 Title: Coporate Controller and CAO	Ken Petersen	04/13/2012

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".

LIST OF SCHEDULES (Electric Utility) (continued)

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission Lines Added During the Year	424-425	
68	Substations	426-427	
69	Transactions with Associated (Affiliated) Companies	429	
70	Footnote Data	450	
	Stockholders' Reports Check appropriate box: [X] Two copies will be submitted [ ] No annual report to stockholders is prepared		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

GENERAL INFORMATION

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

Ken Petersen Coporate Controller and CAO, 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
Electric	Oregon

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

CONTROL OVER RESPONDENT

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

Idaho Power Company is a subsidiary of IDACORP, INC

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

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

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				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1			
2	Chief Executive Officer (3)	J. LaMont Keen	635,000
3			
4	President & Chief Financial Officer (3)	Darrel T. Anderson	383,000
5			
6	Executive Vice President, & Chief Operating Officer (3)	Dan Minor	360,000
7			
8	Senior Vice President, Corporate Responsibilty (1)	Ric Gale	240,000
9			
10	Vice President and Chief Information Officer	Dennis Gribble	212,500
11			
12	Vice President, Human Resources & Corp Services	Luci McDonald	230,000
13			
14	Senior Vice President, Finance and Treasurer (3)	Steven R. Keen	230,000
15			
16	Senior Vice President and General Counsel	Rex Blackburn	270,000
17			
18	Vice President, Chief Risk Officer	Lori Smith	207,500
19			
20	Senior Vice President, Power Supply	Lisa Grow	240,000
21			
22	Vice President, Public Affairs	Jeffrey Malmen	203,000
23			
24	Vice President, Customer Operations	Warren Kline	212,500
25			
26	Vice President Delivery Engineering & Operations	Vern Porter	195,500
27			
28	Corporate Controller & Chief Accounting Officer	Ken Petersen	180,000
29			
30	Vice President, Supply Chain	Naomi Crafton-Shankel	165,000
31			
32	Corporate Secretary	Patrick Harrington	165,000
33			
34	Vice President, Regulatory Affairs (2)	Gregory Said	165,000
35			
36	(1) Retirement 6/30/2011		
37	(2) Title/Position Change effective 1/8/2011		
38	(3) Title changes effective 1/1/2012		
39			
40			
41			
42			
43			
44			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

DIRECTORS

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

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1		
2	Judith A Johansen	2786 Glenmorrie Dr. Lake Oswego, Oregon 97034
3		
4	Christine King	Standard Microsystems Corporation
5		80 Arkay Dr, Hauppauge, NY 11788
6		
7	Gary Michael ***	P.O. Box 1718, Boise, Idaho 83701
8		
9	Stephen Allred	4642 W Dawson Dr Meridian, Id 83646
10		
11	Jan B. Packwood	900 W. Bogus View Drive, Eagle, Idaho 83616
12		
13	J. LaMont Keen, President and Chief Executive Officer**	Idaho Power Company, 1221 W. Idaho Street,
14		P.O. Box 70, Boise, Idaho 83707-0070
15		
16	Richard G. Reiten	Pacwest Center, 1211 SW Fifth Ave., Suite 1600
17		Portland, Oregon 97204
18		
19	Joan Smith	2309 S.W. First Avenue, No. 1141, Portland, Oregon 97201
20		
21	Robert A. Tinstman ***	4433 W. Quail Point Court, Boise, Idaho 83703
22		
23	Thomas Wilford	Alscott Inc, P.O. Box 70001, Boise, Idaho 83701
24		
25	Richard Dahl ***	11659 Presilla Road, Santa Rosa Valley Ca, 93012
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46		
47		
48		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

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

Does the respondent have formula rates?

[X] Yes
[ ] No

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

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	FERC Electric Tariff	FERC Docket No. ER06-787-002,003
2		
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

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

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

[X] Yes
[ ] No

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

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	201109025016	09/01/2011	ER09-1641-000	Idaho Power Company's	FERC Electric Tariff
2				2011-2012 Annual	
3				informational filing	
4				under ER09-1641	
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46					

INFORMATION ON FORMULA RATES
Formula Rate Variances

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

Line No.	Page No(s).	Schedule	Column	Line No
1	None			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				

IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

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

1. None

2. None

3. None

4. None

5. New transmission line - Line #528 Rockland Jct to Rockland Wind Farm 15.92 wire miles
   Additions/removals to existing lines:
   Line #221 added 7.59 wire miles.
   Line #241 extension to Neal Hot Springs added 31.32 wire miles.
   Line #426 customer owned line carries as Idaho Power removed 21.68 wire miles.
   Line #452 dual circuit tap to connect Kimberly station added 5.49 wire miles.
   Line #466 tap to Victory substateion added 5.82 wire miles.
   Line #715 added dual circuit tap Langley Gulch power plant added 16.44 wire miles.

On January 12,2012, Idaho Power, PacifiCorp, and the Bonneville Power Administration (BPA) entered into agreements pertaining to the Boardman-to-Hemingway project.This agreement provides for permitting interests of 21.21 percent for Idaho Power, 24.24 percent for BPA, and 54.55 percent for PacifiCorp.

The Gateway West Transmission Project Development Agreement dated January 12, 2012 between Idaho Power and PacifiCorp outlines the terms under which the parties will jointly own, develop, design, permit and acquire rights-of-way for the Gateway West transmission project.Idaho Power's interest in the Gateway West project applies to four of ten segments involved in the project, referred to as segments 6 (which Idaho Power had previously constructed and is included only for purposes of federal permitting related to the Gateway West project), 8,9,and 10. Each party is responsible for its pro rata share, based on its respective federal and state permitting ownership interest, of the costs incurred under the agreement.Idaho Power's state permitting interest in its segments is 100 percent for segment 6 and 33 percentfor each of segments 8,9, and 10, with a federal permitting interest in the project of 11 percent. Segment #6 is from Borah to Midpoint, segment #8 is from Midpoint to Hemingway, Segment #9 is from Cedar Hill to Hemingway and segment #10 is from Midpoint to Cedar Hill.

6. As of December 31,2011, $300 million remained on Idaho Power's shelf registration for the issuance of first morgage bonds and debt securities. State Commission order number is the same for both issuance OPUC UF4263, IPC-E-10-10, WPSC 20005-32-10.

7. None

8. Effective 1/14/11 a 2.75% general wage increase was implemented.

9. See pages 123.20 to 123.23

10. None

11. None

12. None

13. Refer to pages 104 & 105 for changes in officers and directors. There were a couple of changes in the major security holders for 2011. The top ten institutional shareholders list saw 2 changes from 3rd quarter to 4th quarter. In the 4th quarter Zimmer Lucas Partners, LLC and Thompson, Siegel & Walmsley LLC replaced Artisan Partners Limited Partnership and Fisher Investments.

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	4,473,847,185	4,339,130,398
3	Construction Work in Progress (107)	200-201	591,474,855	416,949,593
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		5,065,322,040	4,756,079,991
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	1,840,782,085	1,771,654,529
6	Net Utility Plant (Enter Total of line 4 less 5)		3,224,539,955	2,984,425,462
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	0	0
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		0	0
9	Nuclear Fuel Assemblies in Reactor (120.3)		0	0
10	Spent Nuclear Fuel (120.4)		0	0
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	0	0
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		0	0
14	Net Utility Plant (Enter Total of lines 6 and 13)		3,224,539,955	2,984,425,462
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		2,081,420	2,074,996
19	(Less) Accum. Prov. for Depr. and Amort. (122)		0	0
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	78,529,519	72,561,774
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		1,852	2,511
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		25,644,107	29,306,774
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		359,418	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		106,616,316	103,946,055
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		19,178,288	73,015,293
36	Special Deposits (132-134)		0	2,802,631
37	Working Fund (135)		37,350	44,850
38	Temporary Cash Investments (136)		100,000	151,172,575
39	Notes Receivable (141)		94,776	303,143
40	Customer Accounts Receivable (142)		67,534,733	63,612,796
41	Other Accounts Receivable (143)		8,206,727	6,166,234
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		1,435,434	1,641,302
43	Notes Receivable from Associated Companies (145)		17,335,019	14,384,928
44	Accounts Receivable from Assoc. Companies (146)		0	0
45	Fuel Stock (151)	227	47,865,097	27,546,983
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	42,015,731	42,221,176
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	4,474,719	3,379,745
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		12,273,571	10,910,213
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	8,128
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		46,440,688	47,964,339
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		3,754,383	573,226
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		359,418	0
65	Derivative Instrument Assets - Hedges (176)		0	0
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	0
67	Total Current and Accrued Assets (Lines 34 through 66)		267,516,230	442,464,958
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		16,992,504	15,869,453
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	0	0
72	Other Regulatory Assets (182.3)	232	989,194,015	761,425,884
73	Prelim. Survey and Investigation Charges (Electric) (183)		491,041	454,727
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		630,208	564,213
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	50,880,202	55,131,472
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		13,613,712	14,524,712
82	Accumulated Deferred Income Taxes (190)	234	227,977,046	157,346,772
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,299,778,728	1,005,317,233
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		4,898,451,229	4,536,153,708

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	97,877,030	97,877,030
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		704,757,436	688,757,435
7	Other Paid-In Capital (208-211)	253	0	0
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	2,096,925	2,096,925
11	Retained Earnings (215, 215.1, 216)	118-119	659,237,261	560,160,116
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	76,066,425	70,098,680
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-11,622,052	-9,567,515
16	Total Proprietary Capital (lines 2 through 15)		1,524,219,175	1,405,228,821
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,465,460,000	1,585,460,000
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	0	0
21	Other Long-Term Debt (224)	256-257	26,266,818	27,330,455
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		3,113,413	3,439,753
24	Total Long-Term Debt (lines 18 through 23)		1,488,613,405	1,609,350,702
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		0	0
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		1,924,461	1,881,776
29	Accumulated Provision for Pensions and Benefits (228.3)		366,648,491	268,433,659
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		33,145,395	21,210,538
32	Long-Term Portion of Derivative Instrument Liabilities		107,763	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		21,366,767	16,951,914
35	Total Other Noncurrent Liabilities (lines 26 through 34)		423,192,877	308,477,887
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		97,996,387	100,785,053
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		1,511,606	1,110,373
41	Customer Deposits (235)		10,799,095	1,366,711
42	Taxes Accrued (236)	262-263	4,895,725	-12,242,872
43	Interest Accrued (237)		22,038,081	24,038,150
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		1,719,933	1,689,273
48	Miscellaneous Current and Accrued Liabilities (242)		33,498,725	112,230,437
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		4,706,863	508,141
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		107,763	0
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		177,058,652	229,485,266
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		19,747,984	23,054,017
57	Accumulated Deferred Investment Tax Credits (255)	266-267	70,840,400	71,972,336
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	27,530,572	26,668,269
60	Other Regulatory Liabilities (254)	278	96,483,245	55,279,902
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		933,326,224	707,009,348
64	Accum. Deferred Income Taxes-Other (283)		137,438,695	99,627,160
65	Total Deferred Credits (lines 56 through 64)		1,285,367,120	983,611,032
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		4,898,451,229	4,536,153,708

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

STATEMENT OF INCOME

Quarterly

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

Annual or Quarterly if applicable

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

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	1,021,585,142	1,033,052,120		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	632,997,464	622,124,906		
5	Maintenance Expenses (402)	320-323	76,104,523	71,096,344		
6	Depreciation Expense (403)	336-337	113,001,742	109,099,197		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	6,764,513	6,857,301		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	-22,723	-22,723		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		28,099	21,955		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	28,894,715	24,046,035		
15	Income Taxes - Federal (409.1)	262-263	-57,754,420	5,967,393		
16	- Other (409.1)	262-263	-803,160	3,057,226		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	116,679,418	83,335,948		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	99,841,847	80,939,819		
19	Investment Tax Credit Adj. - Net (411.4)	266	-1,131,934	-1,533,190		
20	(Less) Gains from Disp. of Utility Plant (411.6)		-17,392	34,607		
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		398,050	444,212		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		814,535,732	842,631,754		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		207,049,410	190,420,366		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

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

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		Line No.
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	
						1
1,021,585,142	1,033,052,120					2
						3
632,997,464	622,124,906					4
76,104,523	71,096,344					5
113,001,742	109,099,197					6
						7
6,764,513	6,857,301					8
-22,723	-22,723					9
						10
						11
28,099	21,955					12
						13
28,894,715	24,046,035					14
-57,754,420	5,967,393					15
-803,160	3,057,226					16
116,679,418	83,335,948					17
99,841,847	80,939,819					18
-1,131,934	-1,533,190					19
-17,392	34,607					20
						21
398,050	444,212					22
						23
						24
814,535,732	842,631,754					25
207,049,410	190,420,366					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		207,049,410	190,420,366		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		1,142,767	802,483		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		974,498	625,141		
33	Revenues From Nonutility Operations (417)		51,602	58,915		
34	(Less) Expenses of Nonutility Operations (417.1)		-18,126	657,070		
35	Nonoperating Rental Income (418)		-3,285	-6,040		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	5,967,745	7,546,332		
37	Interest and Dividend Income (419)		2,178,296	2,167,147		
38	Allowance for Other Funds Used During Construction (419.1)		25,484,071	16,551,145		
39	Miscellaneous Nonoperating Income (421)		1,428,531	1,928,056		
40	Gain on Disposition of Property (421.1)		57,199	122,735		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		35,350,554	27,888,562		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)			3,355		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		718,718	440,052		
46	Life Insurance (426.2)		-757,078	93,378		
47	Penalties (426.3)		430,042	-453,479		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,167,810	1,098,260		
49	Other Deductions (426.5)		6,579,000	5,601,967		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		8,138,492	6,783,533		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	23,238	19,582		
53	Income Taxes-Federal (409.2)	262-263	-638,707	-2,812,996		
54	Income Taxes-Other (409.2)	262-263	-112,459	-559,924		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	511,882	1,739,465		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	1,327,221	1,420,220		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-1,543,267	-3,034,093		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		28,755,329	24,139,122		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		79,348,955	80,490,049		
63	Amort. of Debt Disc. and Expense (428)		1,653,291	1,487,918		
64	Amortization of Loss on Reaquired Debt (428.1)		911,000	915,215		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)					
68	Other Interest Expense (431)		2,474,590	1,707,178		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		13,332,724	10,675,095		
70	Net Interest Charges (Total of lines 62 thru 69)		71,055,112	73,925,265		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		164,749,627	140,634,223		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		164,749,627	140,634,223		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		558,128,446	483,599,149
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		158,781,882	133,087,891
17	Appropriations of Retained Earnings (Acct. 436)			
18	Earnings on Hydro	215.1	-178,017	
19	Reserve for excess Earnings for Cascade Project 2010			(54,644)
20	Reserve for excess Earnings for Twin Falls & American Falls	215.1		(433,060)
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-178,017	(487,704)
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31			-59,704,738	(58,070,890)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-59,704,738	(58,070,890)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		657,027,573	558,128,446
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
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)		2,209,688	2,031,670
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		2,209,688	2,031,670
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		659,237,261	560,160,116
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		70,098,680	62,552,348
50	Equity in Earnings for Year (Credit) (Account 418.1)		5,967,745	7,546,332
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)		76,066,425	70,098,680

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	164,749,627	140,634,223
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	113,001,742	109,099,197
5	Amortization of	11,025,871	12,120,185
6			
7			
8	Deferred Income Taxes (Net)	-58,819,227	75,464,788
9	Investment Tax Credit Adjustment (Net)	-726,590	-984,156
10	Net (Increase) Decrease in Receivables	-2,125,936	13,653,023
11	Net (Increase) Decrease in Inventory	-21,207,643	539,767
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	22,896,607	-5,534,463
14	Net (Increase) Decrease in Other Regulatory Assets	23,708,446	34,996,161
15	Net Increase (Decrease) in Other Regulatory Liabilities	44,336,626	11,513,932
16	(Less) Allowance for Other Funds Used During Construction	25,484,071	16,551,145
17	(Less) Undistributed Earnings from Subsidiary Companies	5,967,745	7,546,282
18	Other (provide details in footnote):	27,407,254	-41,492,468
19			
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	292,794,961	325,912,762
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-324,431,776	-327,576,965
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	13,332,724	10,675,095
31	Other (provide details in footnote):	6,314,273	25,390,083
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-331,450,227	-312,861,977
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
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)		-7,000,000
45	Proceeds from Sales of Investment Securities (a)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

STATEMENT OF CASH FLOWS

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

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48			
49	Net (Increase) Decrease in Receivables	208,367	333,525
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):	-493,891	8,541,146
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-331,735,751	-310,987,306
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): Capital Infusion from IDACORP	16,000,000	50,000,000
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	16,000,000	250,000,000
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-121,063,636	-1,063,636
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):	-1,207,914	-3,183,141
77			
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-59,704,738	-58,070,890
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-165,976,288	187,682,333
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-204,917,078	202,607,789
87			
88	Cash and Cash Equivalents at Beginning of Period	224,232,718	21,624,929
89			
90	Cash and Cash Equivalents at End of period	19,315,640	224,232,718

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

Amortization	Twelve Months Ended 12/31/11
Plant	6,741,790
Regulatory assets	312,521
Regulatory liabilities	(465,593)
Unamortized debt expense	2,509,015
Unamortized discount	326,339
Water rights	1,042,009
Other	559,790
	11,025,871

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

Cash paid during the period for:	
Income taxes	(1,033,185)
Interest (net of amount capitalized)	70,490,892

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

Cash Flow from Operating Activities (Other)	Twelve Months Ended 12/31/11
Pension and postretirement benefit plan expense	45,223,307
Contributions to pension and postretirement benefit plans	(22,088,331)
Gain on sale of renewable energy certificates	(398,050)
Unbilled revenues	1,523,652
Other noncash adjustments to net income	1,762,799
Accrued interest	(2,000,069)
Customer deposits	9,432,385
Other assets and liabilities	(6,048,439)
	27,407,254

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

Non-cash investing activities:	
Additions to PP&E in accounts payable	26,330,730

Schedule Page: 120 Line No.: 31 Column: b

Other Cash Flows from Plant	Twelve Months Ended 12/31/11
Sale of emission allowances and renewable energy certificates	6,314,273
	6,314,273

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

Other Investing Cash Flows	Twelve Months Ended 12/31/11
Disbursements from rabbi trust	2,491,855
Net change in notes receivable from subsidiary	(2,950,091)
Miscellaneous other investing activities	(35,655)
	(493,891)

NOTES TO FINANCIAL STATEMENTS

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

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

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES:

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

Basis of Reporting

The financial statements include the assets, liabilities, revenues and expenses of the Company and have been prepared in accordance with the accounting requirements of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America (U.S. GAAP). As required by the FERC, the Company accounts for its investment in its majority-owned subsidiary on the equity method rather than consolidating the assets, liabilities, revenues, and expenses of the subsidiary, as required by U.S. GAAP. The accompanying financial statements include the Company's proportionate share of utility plant and related operations resulting from its interest in jointly owned plants. In addition, under the requirements of the FERC, there are differences from U.S. GAAP in the presentation of (l) current portion of long-term debt, (2) assets and liabilities for cost of removal of assets, (3) regulatory assets and liabilities, (4) deferred income taxes, (5) income tax expense and (6) non-utility revenues.

Management Estimates

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

System of Accounts

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

Regulation of Utility Operations

Idaho Power's financial statements reflect the effects of the different ratemaking principles followed by the jurisdictions regulating Idaho Power. The application of accounting principles related to regulated operations sometimes results in Idaho Power recording expenses and revenues in a different period than when an unregulated enterprise would. In these instances, the amounts are deferred as regulatory assets or regulatory liabilities on the balance sheet and recorded on the income statement when recovered or returned in rates. Additionally, regulators can impose regulatory liabilities upon a regulated company for amounts previously collected from customers and for amounts that are expected to be refunded to customers. The effects of applying these regulatory accounting principles to Idaho Power's operations are discussed in more detail in Note 3.

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand and highly-liquid temporary investments that mature within 90 days of the date of acquisition.

Receivables and Allowance for Uncollectible Accounts

Customer receivables are recorded at the invoiced amounts and do not bear interest. A late payment fee of one percent may be assessed on account balances after 30 days. An allowance is recorded for potential uncollectible accounts. The allowance is reviewed periodically and adjusted based upon a combination of historical write-off experience, aging of accounts receivable, and an analysis of specific customer accounts. Adjustments are charged to income. Customer accounts receivable balances that remain outstanding after reasonable collection efforts are written off through a charge to the allowance and a credit to accounts receivable.

Other receivables, are also reviewed for impairment periodically, based upon transaction-specific facts. When it is probable that Idaho Power will be unable to collect all amounts due according to the contractual terms of the agreement, an allowance is established for the estimated uncollectible portion of the receivable and charged to income.

There were no impaired receivables without related allowances at December 31, 2011 and 2010. Once a receivable is determined to be impaired, any further interest income recognized is fully reserved.

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

Revenues
Operating revenues related to Idaho Power's sale of energy are recorded when service is rendered or energy is delivered to customers. Idaho Power accrues estimated unbilled revenues for electric services delivered to customers but not yet billed at year-end. Idaho Power collects franchise fees and similar taxes related to energy consumption. None of these collections are reported on the income statement. Beginning in February 2009, Idaho Power is collecting in base rates a portion of the allowance for funds used during construction (AFUDC) related to its Hells Canyon relicensing project. Cash collected under this ratemaking mechanism is not recorded as revenue, but is instead recorded as a regulatory liability.

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

All utility plant in service is depreciated using the straight-line method at rates approved by regulatory authorities. Annual depreciation provisions as a percent of average depreciable utility plant in service approximated 2.83 percent in 2011 and 2.84 percent in 2010.

Long-lived assets are periodically reviewed for impairment when events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If the sum of the undiscounted expected future cash flows from an asset is less than the carrying value of the asset, impairment must be recognized in the financial statements. There were no material impairments of these assets in 2011 or 2010.

Allowance for Funds Used During Construction
AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. With one exception, cash is not realized currently from such allowance; it is realized under the ratemaking process over the service life of the related property through increased revenues resulting from a higher rate base and higher depreciation expense. The component of AFUDC attributable to borrowed funds is included as a reduction to interest expense, while the equity component is included in other income. Idaho Power's weighted-average monthly AFUDC rates for 2011 and 2010 were 7.8 percent and 8.0 percent, respectively. Idaho Power's reductions to interest expense for AFUDC were $13 million for 2011 and $11 million for 2010. Other income included $25 million and $17

million of AFUDC for 2011 and 2010, respectively.

Income Taxes

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

Consistent with orders and directives of the Idaho Public Utilities Commission (IPUC), the regulatory authority having principal jurisdiction over Idaho Power's Idaho service territory, Idaho Power's deferred income taxes for plant-related items (commonly referred to as normalized accounting) are primarily provided for the difference between income tax depreciation and book depreciation used for financial statement purposes. Unless contrary to applicable income tax guidance, deferred income taxes are not provided for those income tax timing differences where the prescribed regulatory accounting methods direct Idaho Power to recognize the tax impact currently for rate making and financial reporting. Regulated enterprises are required to recognize such adjustments as regulatory assets or liabilities if it is probable that such amounts will be recovered from or returned to customers in future rates.

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

Income taxes are discussed in more detail in Note 2.

Comprehensive Income

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

	2011	2010
	(thousands of dollars)	
Unrealized holding gains on available-for-sale securities	$ 2,569	$ 2,969
Senior Management Security Plan	(14,191)	(12,537)
Total	$ (11,622)	$ (9,568)

Other Accounting Policies

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

New Accounting Pronouncements

The Financial Accounting Standards Board (FASB) has issued the following accounting guidance, which is effective for years beginning after December 15, 2011:

- In May 2011, the FASB issued guidance to provide a consistent definition of fair value and ensure that the fair value measurement and disclosure requirements are similar between generally accepted accounting principles in the United States and International Financial Reporting Standards. The guidance changes certain fair value measurement principles and enhances the disclosure requirements, particularly for Level 3 fair value measurements. Idaho Power is currently assessing the impact of the guidance but do not believe that the adoption of this guidance will have a material effect on their consolidated financial statements.

2. INCOME TAXES:

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

	2011	2010
	(thousands of dollars)	
Federal income tax expense at 35% statutory rate	$ 42,116	$ 51,614
Change in taxes resulting from:		
Equity earnings of subsidiary companies	(2,089)	(2,641)
AFUDC	(13,586)	(9,529)
Capitalized interest	6,465	3,674
Investment tax credits	(3,355)	(3,378)
Removal costs	(2,244)	(2,850)
Capitalized overhead costs	(5,950)	(3,500)
Capitalized repair costs	(14,000)	(10,500)
Tax method change - uniform capitalization	-	(65,333)
Tax method change – capitalized repairs	-	(44,466)
Uncertain tax positions - established	-	74,436
Uncertain tax positions – settled	(63,138)	(1,138)
State income taxes, net of federal benefit	1,846	5,074
Depreciation	14,100	13,138
Other, net	(4,583)	2,233
Total income tax (benefit) expense	$ (44,418)	$ 6,834
Effective tax rate	(36.91%)	4.6 %

The items comprising income tax (benefit) expense are as follows:

	2011	2010
	(thousands of dollars)	
Income taxes currently payable:		
Federal	$ 7,832	$ (62,068)
State	7,296	(5,579)
Total	15,128	(67,647)
Income taxes deferred:		
Federal	22,942	6,752
State	(6,920)	(4,036)
Total	16,022	2,716
Uncertain tax positions:		
Federal	(66,225)	65,222
State	(8,211)	8,076
Total	(74,436)	73,298
Investment tax credits:		
Deferred	2,223	1,844
Restored	(3,355)	(3,377)
Total	(1,132)	(1,533)
Total income tax (benefit) expense	$ (44,418)	$ 6,834

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

	2011	2010
	(thousands of dollars)	
Deferred tax assets:		
Regulatory liabilities	$ 45,473	$ 46,199
Advances for construction	5,118	7,061
Deferred compensation	22,067	21,045
Advanced payments	12,958	8,292
Power cost adjustments	1,711	-
Tax credits	8,547	6,461
Revenue sharing	10,594	-
Retirement benefits	122,445	88,827
Other	3,758	4,422
Total	232,671	182,307
Deferred tax liabilities:		
Property, plant and equipment	333,335	284,794
Regulatory assets	599,992	422,216
Conservation programs	3,464	7,611
Power cost adjustments	-	11,833
Retirement benefits	122,712	93,997
Other	15,956	11,146
Total	1,075,459	831,597
Net deferred tax liabilities	$ 842,788	$ 649,290

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

Tax Credits Carryforwards

As of December 31, 2011, Idaho Power had $8.5 million of Idaho investment tax credit carryforward. Idaho investment tax credit expires from 2023 to 2025.

Uncertain Tax Positions

A reconciliation of the beginning and ending amount of unrecognized tax benefits for Idaho Power is as follows (in thousands of dollars):

	2011	2010
Balance at January 1,	$ 74,436	$ 1,138
Additions for tax positions of the current year	—	2,822
Additions for tax positions of prior years	—	71,614
Reductions for tax positions of prior years	(66,379)	(1,138)
Settlements with taxing authorities	(8,057)	—
Balance at December 31,	$ —	$ 74,436

Idaho Power recognizes interest accrued related to unrecognized tax benefits as interest expense and penalties as other expense. Idaho Power recognized a net reduction in interest expense of $0.2 million in 2011and interest expense of $0.2 million in 2010. Accrued interest was was zero as of December 31, 2011and $0.2 million as of December 31, 2010. No penalties are accrued.

IDACORP and Idaho Power are subject to examination by their major tax jurisdictions - U.S. federal and the State of Idaho. The open tax years are 2011 for federal and 2008-2011 for Idaho. In May 2009, IDACORP and Idaho Power formally entered the U.S. Internal Revenue Service (IRS) Compliance Assurance Process (CAP) program for their 2009 tax year and has remained in the CAP program for all subsequent years. The CAP program provides for IRS examination and issue resolution throughout the current year with the objective of return filings containing no contested items.

With the resolution of Idaho Power's capitalized repairs and uniform capitalization tax accounting methods examinations (discussed below), the 2009 tax year is now closed for federal purposes. In 2011, the IRS also completed its examination of IDACORP's 2010 tax year with no unresolved income tax issues. Idaho Power believes there are no remaining material tax uncertainties for 2011 and prior tax years.

Tax Accounting Method Change for Repair-Related Expenditures

In June 2010, Idaho Power completed its evaluation of a tax accounting method change for its 2009 tax year that allows a current income tax deduction for repair-related expenditures on its utility assets that are currently capitalized for financial reporting and tax purposes. In September 2010, Idaho Power adopted this method following the automatic consent procedures with the filing of IDACORP's 2009 consolidated federal income tax return. The method was subject to audit under IDACORP's 2009 CAP examination.

For the year ended December 31, 2010, Idaho Power recorded a $44.5 million tax benefit related to the filed deduction for the cumulative method change adjustment and an additional $11.7 million tax benefit for the annual deduction estimate included in its 2010 income tax provision. As of December 31, 2010, Idaho Power had a current uncertain tax position liability of $14.7 million related to this method.

In April 2011, IDACORP and the IRS reached an agreement on Idaho Power's tax accounting method change for capitalized repairs. Accordingly, the IRS finalized the 2009 CAP examination and submitted its report on the 2009 tax year to the U.S. Congress Joint Committee on Taxation (Joint Committee) for review. Idaho Power considers the capitalized repairs method effectively settled and believes that no material income tax uncertainties remain for the method. As such, Idaho Power recognized $3.4 million of its previously unrecognized tax benefits for this method in 2011.

For the year ended December 31, 2011, the capitalized repairs annual tax deduction estimate included in Idaho Power's income tax provision produced a $15.6 million tax benefit. The amount of this annual tax deduction will vary depending on a number of factors, but most directly by the amount and type of Idaho Power's annual capital additions. The reversal of this temporary difference from prior years will offset a portion of the ongoing annual benefit.

Idaho Power's prescribed regulatory accounting treatment requires immediate income recognition for temporary tax differences of this type. A regulatory asset is established to reflect Idaho Power's ability to recover increased income tax expense when such temporary differences reverse.

Tax Accounting Method Change for Uniform Capitalization

In September 2009, the IRS issued Industry Director Directive #5 (IDD), which discusses the IRS's compliance priorities and audit techniques related to the allocation of mixed service costs in the uniform capitalization methods of electric utilities. Within IDACORP's 2009 CAP examination, the IRS and Idaho Power worked through the impact the IDD guidance had on Idaho Power's uniform capitalization method and reached agreement during 2010. The agreement provided that Idaho Power change its uniform capitalization method to the agreed upon method under the IDD with the filing of IDACORP's 2009 consolidated federal income tax return. While Idaho Power had an agreement with the IRS for examination and return filing purposes, the agreement required Joint Committee approval to be final.

The resulting tax deductions available under the agreed upon uniform capitalization method were significantly greater than Idaho Power's prior method. For the year ended December 31, 2010, Idaho Power recorded a tax benefit of $65.3 million related to the cumulative method change adjustment (tax years 1986 through 2009) for this method and $5.6 million of tax expense from the reversal of this temporary difference. As of December 31, 2010, Idaho Power had a current uncertain tax position liability equal to the $59.7 million net tax benefit recorded for the method change. Due to the method change agreement with the IRS, Idaho Power reversed the uncertain tax position liability for its 2009 uniform capitalization deduction, resulting in a $1.1 million tax benefit for the year ended December 31, 2010.

In September 2011, the IRS notified IDACORP that the Joint Committee had completed its review of IDACORP's 2009 tax year and approved the uniform capitalization method agreement. Idaho Power considers the uniform capitalization method effectively settled and believes that no material income tax uncertainties remain for the method. Accordingly, Idaho Power recognized $56.9 million of its previously unrecognized tax benefits for tax years 2009 and prior in 2011.

For the year ended December 31, 2011, the uniform capitalization annual tax deduction estimate included in Idaho Power's income tax provision produced a $6.6 million tax benefit. The amount of this annual tax deduction will vary depending on a number of factors, but most directly by the amount and type of Idaho Power's annual capital additions. The reversal of this temporary difference from prior years will offset a portion of the ongoing annual benefit. The prescribed regulatory accounting treatment for this method is the same as discussed earlier for the capitalized repairs method.

Cash Impacts of Tax Method Changes

In 2011, Idaho Power paid previously accrued income tax liabilities of $8.1 million, related to the capitalized repairs examination agreement. There were no 2011 cash impacts related to the uniform capitalization method settlement as income tax refunds for the method change were received in 2010.

In 2010, Idaho Power realized federal and state cash benefits associated with the 2009 capitalized repairs and uniform capitalization method changes of $42 million. The majority of this cash benefit was realized through reductions to cash payments that would have otherwise been owed to taxing authorities for the 2009 tax year and a federal refund of $24 million received in 2010. Additionally, approximately $6 million of state cash benefits were realized through reduced tax payments for the 2010 year.

The capitalized repairs and uniform capitalization method changes produced an income statement tax benefit of $44.5 million and $65.3 million, respectively, in 2010 prior to the accrual for uncertain tax positions. A portion of this earnings benefit related to previously deferred income tax expense being flowed through the income statement, which does not deliver any cash benefits. In addition, federal tax credits of $17 million previously recognized were restored due to the reduction of 2009 taxable income by the two method changes. The restored credits were a reduction to cash received in 2010, but will be available to deliver cash benefits in future periods.

3. REGULATORY MATTERS

Regulatory Assets and Liabilities

Regulatory assets represent incurred costs that have been deferred because it is reasonably expected they will be recovered through future rates collected from customers. Regulatory liabilities represent obligations to make refunds to customers for previous collections, except for cost of removal (which represents the cost of removing future electric assets). The following table presents a summary of Idaho Power’s regulatory assets and liabilities (in thousands of dollars):

Description	Remaining Amortization Period	Earning a Return (1)	Not Earning a Return	Total as of December 31, 2011	Total as of December 31, 2010
Regulatory Assets:					
Income taxes		$ —	$ 603,772	$ 603,772	$ 429,457
Unfunded postretirement benefits(2)		—	262,503	262,503	182,742
Pension expense deferrals(3)	2012-2015	38,976	19,068	58,044	63,833
Energy efficiency program costs(3)		15,956	—	15,956	19,467
Power supply costs(3)	Varies	8,490	—	8,490	29,753
Fixed cost adjustment(3)	Varies	14,457	—	14,457	12,340
Asset retirement obligations(4)		—	15,557	15,557	15,372
Mark-to-market liabilities(5)		—	4,707	4,707	2,278
Other	2012-2021	993	2,868	3,861	6,184
Total		$ 78,872	$ 908,475	$ 987,347	$ 761,426
Regulatory Liabilities:					
Income taxes		$ —	$ 49,253	$ 49,253	$ 53,440
Removal costs(4)		—	163,173	163,173	157,642
Investment tax credits		—	70,841	70,841	71,972
Deferred revenue-AFUDC (3)		21,034	12,111	33,145	21,211
Power supply costs (3)	Varies	13,121	—	13,121	—
2010 Settlement agreement sharing mechanism(3)	2013	27,099	—	27,099	—
Mark-to-market assets(5)		—	3,754	3,754	573
Other	2012	1,250	159	1,409	8,508
Total		$ 62,504	$ 299,291	$ 361,795	$ 313,346

(1) Earning a return includes either interest or a return on the investment as a component of rate base at the allowed rate of return.

(2) Represents the unfunded obligation of Idaho Power's pension and postretirement benefit plans, which are discussed in Note 10.

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

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

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

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

Power Cost Adjustment Mechanisms and Deferred Power Supply Costs

In both its Idaho and Oregon jurisdictions, Idaho Power's power cost adjustment (PCA) mechanisms address the volatility of power supply costs and provide for annual adjustments to the rates charged to its retail customers. The PCA mechanisms compare Idaho Power's actual and forecast net power supply costs (primarily fuel and purchased power less off-system sales) against net power supply costs currently being recovered in retail rates.

Under the PCA mechanisms, certain differences between actual net power supply costs incurred by Idaho Power and the costs included in retail rates are recorded as a deferred charge or credit on the balance sheets for future recovery or refund through retail rates. The power supply costs deferred primarily result from changes in wholesale market prices and transaction volumes, changes in contracted power purchase prices and volumes, and the levels of hydroelectric and thermal generation.

Idaho Jurisdiction Power Cost Adjustment Mechanism: In the Idaho jurisdiction, the annual PCA adjustments are based on (a) a forecast component, based on a forecast of net power supply costs in the coming year as compared to net power supply costs in base rates; and (b) a true-up component, based on the difference between the previous year's actual net power supply costs and the previous year's forecast. The latter component also includes a balancing mechanism so that, over time, the actual collection or refund of authorized true-up dollars matches the amounts authorized. The Idaho PCA mechanism also includes:

- a cost or benefit sharing ratio that allocates the deviations in net power supply expenses between customers (95 percent) and shareholders (5 percent), with the exception of expenses associated with PURPA power purchases, which are allocated 100 percent to customers;
- a load change adjustment rate (LCAR), which is intended to eliminate recovery of power supply expenses already collected in rates associated with load changes resulting from changing weather conditions, a growing customer base, or changing customer use patterns; and
- third-party transmission expenses (paid to third parties to facilitate wholesale purchases and sales of energy) as a component of net power supply costs for purposes of calculating the PCA.

The table below summarizes Idaho PCA rate adjustments during the years ended December 31, 2011and 2010.

Effective Date	$ Change (millions)	Notes
June 1, 2011	$ (40.4)	The reduction to Idaho PCA rates was net of $10.0 million of Idaho Power's energy efficiency rider deferral balance that the IPUC authorized for recovery in Idaho Power's Idaho PCA rates.
June 1, 2010	$ (146.9)	The IPUC's order was made in conjunction with a January 2010 rate settlement agreement described below in "January 2010 and December 2011 Idaho Settlement Agreements." Concurrent with the PCA rate decrease, the IPUC authorized an $88.7 million increase in base rates, $63.7 million of which was related to power supply costs.

Oregon Jurisdiction Power Cost Adjustment Mechanism: Idaho Power's power cost recovery mechanism in Oregon has two components: an annual power cost update (APCU) and a power cost adjustment mechanism (PCAM). The APCU allows Idaho Power to reestablish its Oregon base net power supply costs annually, separate from a general rate case, and to forecast net power supply costs for the upcoming water year. The PCAM is a true-up filed annually in February. The filing calculates the deviation between actual net power supply expenses incurred for the preceding calendar year and the net power supply expenses recovered through the APCU for the same period. Under the PCAM, Idaho Power is subject to a portion of the business risk or benefit associated with this deviation through application of an asymmetrical deadband (or range of deviations) within which Idaho Power absorbs cost increases or decreases. For deviations in actual power supply costs outside of the deadband, the PCAM provides for 90/10 sharing of costs and benefits between customers and Idaho Power. However, collection by Idaho Power will occur only to the extent that Idaho Power's actual return on equity (ROE) for the year is no greater than 100 basis points below Idaho Power's last authorized ROE. A refund to customers will occur only to the extent that Idaho Power's actual ROE for that year is no less than 100 basis points above Idaho Power's last authorized ROE.

Oregon jurisdiction power supply cost changes under the APCU and PCAM during the years ended December 31, 2011 and 2010 were as follows:

Year and Mechanism	APCU or PCAM Adjustment
2011 PCAM	Actual net power supply costs were below the deadband, resulting in a $1.5 million deferral.
2011 APCU	A rate decrease of $2.2 million annually took effect June 1, 2011.
2010 PCAM	Actual net power supply costs were within the deadband, resulting in no deferral.
2010 APCU	A rate increase of $2.6 million annually took effect June 1, 2010.

Idaho Regulatory Matters

2011 Idaho General Rate Case and Settlement: On June 1, 2011, Idaho Power filed a general rate case and proposed rate schedules with the IPUC, Case No. IPC-E-11-08. The filing was based on a 2011 test year and requested approximately $82.6 million in additional Idaho jurisdiction annual revenues in base rates, a 9.9 percent overall average rate increase for Idaho customers.

On September 23, 2011, Idaho Power, the IPUC Staff, and other interested parties publicly filed a settlement stipulation with the IPUC resolving most of the key contested issues in the Idaho general rate case. On December 30, 2011, the IPUC issued an order approving the settlement stipulation. The settlement stipulation approved by the December 30, 2011 order provides for a 7.86 percent authorized rate of return on an Idaho-jurisdictional rate base of approximately $2.36 billion. The approved settlement stipulation resulted in a 4.07 percent, or $34.0 million, overall increase in Idaho Power's annual Idaho jurisdictional base rate revenues, effective January 1, 2012. Neither the order nor the settlement stipulation specified an authorized rate of return on equity.

The settlement stipulation approved by the order also addressed Idaho Power's calculation of the LCAR to be applied in Idaho Power's PCA mechanism. The LCAR adjusts power supply cost recovery within the Idaho PCA formula upwards or downwards for differences between actual load and the load used in calculating base rates. The settlement stipulation provides for a LCAR of $18.16 per megawatt-hour, effective January 1, 2012, compared to the rate of $19.67 per megawatt-hour in effect prior to that date.

In its general rate case application, Idaho Power had requested approval of the current fixed cost adjustment (FCA) mechanism pilot program, described below, as a permanent rate mechanism for residential and small commercial class customers. Neither the December 30, 2011 order nor the settlement stipulation resolves whether the fixed cost adjustment pilot program should be made permanent.

Neither the order nor the settlement stipulation imposes a moratorium on Idaho Power's filing a general revenue requirement case at a future date.

January 2010 and December 2011 Idaho Settlement Agreements: On January 13, 2010, the IPUC approved a settlement agreement among Idaho Power, several of Idaho Power’s customers, the IPUC Staff, and others. Significant elements of the settlement agreement included:

- a specified distribution of the reduction in 2010 PCA that would reduce customer rates, provide up to a $25 million general increase in annual base rates, and reset base power supply costs for the PCA, effective with the June 1, 2010 PCA rate change. This provision anticipated a significant reduction in PCA rates for the 2010-2011 PCA year;
- a provision to share with Idaho customers 50 percent of any Idaho-jurisdiction earnings in excess of a 10.5 percent return on equity in any calendar year from 2009 to 2011; and
- a provision to allow the additional amortization of accumulated deferred investment tax credits (ADITC) if Idaho Power's Idaho-jurisdiction rate of return on year-end equity (Idaho ROE) is below 9.5 percent in any calendar year from 2009 to 2011. Idaho Power was permitted to amortize additional ADITC in an amount up to $45 million over the three-year period, but could use no more than $15 million in any one year unless there is a carryover. Carryover amounts were added to the $15 million annual allowance up to a maximum amortization of $25 million in any one year.

On April 15, 2010, Idaho Power filed its annual application with the IPUC to implement new PCA rates to be effective June 1, 2010 through May 31, 2011, and to change base rates, pursuant to the terms of the January 2010 Idaho settlement agreement. On May 28, 2010, the IPUC issued its order approving a $146.9 million decrease in the PCA, along with a base rate increase of $88.7 million. The net effect of these two rate adjustments was an overall decrease in customer rates of $58.2 million, effective June 1, 2010. The $88.7 million base rate increase reflects a $63.7 million increase in base power supply costs and a $25 million increase in base rates.

Because Idaho Power’s actual Idaho ROE was between 9.5 and 10.5 percent in 2009 and 2010, the sharing and amortization provisions of the January 2010 settlement agreement were not triggered. However, recognition of income tax benefits in 2011 had a significant impact on Idaho Power's actual Idaho ROE and contributed to the triggering of the sharing mechanism for 2011. In accordance with the terms of the settlement agreement, Idaho Power recorded a $27.1 million reduction in revenue and regulatory liability in 2011, reflecting 50 percent of Idaho Power's 2011 Idaho-jurisdictional earnings above a 10.5 percent Idaho ROE to be shared with Idaho customers.

The sharing and ADITC amortization provisions of the January 2010 settlement agreement terminated on December 31, 2011. On December 27, 2011, the IPUC issued an order, separate from the general rate case proceeding, approving a settlement stipulation that had been executed by Idaho Power, the IPUC Staff, and one large industrial customer of Idaho Power and filed with the IPUC on December 12, 2011. The settlement stipulation provides that:

- if Idaho Power's actual Idaho ROE for 2012, 2013, or 2014 is less than 9.5 percent, then Idaho Power may amortize additional ADITC to help achieve a minimum 9.5 percent Idaho ROE in the applicable year. Idaho Power would be permitted to amortize additional ADITC in an aggregate amount up to $45 million over the three-year period, but could use no more that $25 million in 2012;
- if Idaho Power's actual Idaho ROE for 2012, 2013, or 2014 exceeds 10.0 percent, the amount of Idaho Power's Idaho jurisdictional earnings exceeding a 10.0 percent, but less than a 10.5 percent, Idaho ROE for the applicable year would be shared equally between Idaho Power and its Idaho customers; and
- if Idaho Power's actual Idaho ROE for 2012, 2013, or 2014 exceeds 10.5 percent, the amount of Idaho Power's Idaho jurisdictional earnings exceeding a 10.5 percent Idaho ROE for the applicable year would be allocated 75 percent to Idaho Power's Idaho customers and 25 percent to Idaho Power.

The settlement stipulation provides that the return on year-end equity thresholds (9.5 percent, 10.0 percent, and 10.5 percent) will be automatically adjusted prospectively in the event the IPUC approves a change to Idaho Power's authorized return on equity as part of a general rate case proceeding seeking a rate change effective prior to January 1, 2015. The automatic adjustments would be as follows: (a) the 9.5 percent return on year-end equity trigger in the settlement stipulation would be replaced by the percentage equal to 95 percent of the new authorized return on equity, (b) the 10.0 percent return on year-end equity trigger in the settlement stipulation would be re-established at the new authorized return on equity amount, and (c) the 10.5 percent return on year-end equity trigger in the settlement stipulation would be replaced by the percentage equal to 105 percent of the new authorized return on equity.

In consideration of these terms, the settlement stipulation provided that Idaho Power would also allocate to customers 75 percent of Idaho Power's own share of 2011 Idaho jurisdictional earnings over a 10.5 percent Idaho ROE. As a result, Idaho Power recorded in 2011 a $20.3 million pre-tax charge to pension expense and an associated decrease in deferred pension regulatory asset, representing the additional amount to be allocated to Idaho customers.

Idaho Fixed Cost Adjustment : The FCA began as a pilot program for Idaho Power’s Idaho residential and small general service customers, running from 2007 through 2009. The FCA is designed to remove Idaho Power’s disincentive to invest in energy efficiency programs by separating (or decoupling) the recovery of fixed costs from the variable kilowatt-hour charge and linking it instead to a set amount per customer. On April 29, 2010, the IPUC approved a two-year extension of the FCA pilot program, effective retroactive to January 1, 2010, through December 31, 2011. On October 19, 2011, Idaho Power filed an application with the IPUC requesting that the FCA pilot program become permanent for residential and small general service customer classes effective January 1, 2012; a determination from the IPUC is pending.

The following table summarizes recent FCA rate adjustments:

FCA Year	Period rates in effect	Annual Amount (in millions)
2010	June 1, 2011-May 31, 2012	9.3
2009	June 1, 2010-May 31, 2011	6.3

2008	June 1, 2009-May 31, 2010	2.7

As of December 31, 2011, the deferral balance for the FCA was $14.5 million.

Defined Benefit Pension Plan Contribution Recovery: Idaho Power defers its Idaho-jurisdiction pension expense as a regulatory asset until recovered from Idaho customers. As of December 31, 2011, Idaho Power's deferral balance was $58.0 million. Deferred pension costs are expected to be amortized to expense to match the revenues received when contributions are recovered through rates. Idaho Power only records a carrying charge on the unrecovered balance of cash contributions.

In May 2010, the IPUC approved Idaho Power’s request to increase rates to allow recovery of Idaho Power’s 2009 cash contribution to its defined benefit pension plan, which contribution was made in September 2010. Idaho Power’s application sought approval of $5.4 million in pension cost recovery over a one-year period to allow recovery contemporaneous with Idaho Power’s expected cash contributions to the plan.

In September 2010, Idaho Power elected to make a $60 million contribution to its defined benefit pension plan, rather than the minimum required funding amount, to bring the defined benefit pension plan to a more funded position, potentially reducing future required contributions and Pension Benefit Guaranty Corporation premiums. On October 1, 2010, Idaho Power filed an application with the IPUC requesting an order accepting Idaho Power's 2011 retirement benefits package, but not requesting recovery through rates of additional pension plan contributions. On April 28, 2011, the IPUC issued an order accepting Idaho Power's 2011 retirement benefits package.

On March 15, 2011, Idaho Power filed an application with the IPUC requesting an increase in the amount included in base rates for recovery of the Idaho-allocated portion of Idaho Power's cash contributions to its defined benefit pension plan from the then-current amount of $5.4 million to approximately $17.1 million annually. On May 19, 2011, the IPUC approved Idaho Power’s application, with new rates effective on June 1, 2011. In September 2011, Idaho Power contributed an additional $18.5 million to its defined benefit pension plan.

Transmission Revenue Shortfall Filing: On January 15, 2009, the FERC issued an order that required Idaho Power to reduce its transmission service rates to FERC jurisdictional customers and refund to transmission customers transmission revenues that Idaho Power had received starting in 2006. This refund ultimately resulted in under-recovery of transmission costs by Idaho Power, and in October 2009 the IPUC authorized Idaho Power to record an Idaho-jurisdiction regulatory asset for the transmission revenue shortfall, for future recovery in customer rates. At December 31, 2011, the transmission revenue shortfall was $2.1 million. The IPUC ordered that Idaho Power advise the IPUC when the FERC has issued its order on rehearing, following which Idaho Power may request a commencement date for the amortization period for the regulatory asset. On December 7, 2011, the FERC issued an order denying rehearing. Accordingly, on February 15, 2012, Idaho Power submitted an application to the IPUC seeking to include the $2.1 million transmission revenue shortfall in customer rates, recoverable over a three-year period beginning June 1, 2012. As of the date of this report, a determination and order from the IPUC is pending.

Energy Efficiency and Demand Response Programs: Idaho Power has implemented and/or manages a wide range of opportunities for its customers to participate in energy efficiency and demand response programs.

On August 18, 2011, the IPUC issued an order approving Idaho Power's March 2011 application requesting that the IPUC designate Idaho Power's 2010 Idaho energy efficiency rider expenditures of approximately $42 million as prudently incurred expenses. Idaho Power’s 2010 expenditures for rider-funded energy efficiency and demand response initiatives in its Idaho and Oregon jurisdictions totaled $44.2 million. On March 16, 2010, Idaho Power filed an application with the IPUC requesting an order designating energy efficiency expenditures of $50.7 million incurred in 2008 and 2009 as prudently incurred expenses. On November 16, 2010, the IPUC issued an order designating all $50.7 million of energy efficiency expenditures as prudently incurred and approved for ratemaking purposes.

On October 22, 2010, Idaho Power filed an application with the IPUC requesting acceptance of the company's demand-side resources (DSR) business model, which included a request for authorization to (a) move demand response incentive payments out of the energy efficiency rider and into the Idaho PCA on a prospective basis beginning on June 1, 2011, and thus subject to a true-up under the PCA mechanism; (b) establish a regulatory asset for the direct incentive payments associated with Idaho Power's energy efficiency program for large commercial and industrial customers, beginning January 1, 2011, so that Idaho Power may capitalize the direct incentive payments associated with the program, include the costs associated with the program incentive payments in its rate base, and thus earn a rate of return on a portion of its DSR activities; and (c) change the carrying charge on the existing energy efficiency rider balancing account (from the then-current interest rate of 1.0 percent to Idaho Power's authorized rate of return). On April 1, 2011, the IPUC issued an order stating that certain issues raised in the application are more properly considered in a general rate case proceeding. However, the IPUC noted in its order that Idaho Power's energy efficiency rider balance includes approximately $10 million in expenditures that have been previously approved by the IPUC for recovery, and thus authorized recovery of $10 million of the rider balance in Idaho Power's Idaho PCA rates, beginning June 1, 2011. In that order, the IPUC did not approve a change to the energy efficiency rider balance carrying charge.

On May 17, 2011, the IPUC issued an order stating that it will allow Idaho Power to account for specified direct incentive payments associated with Idaho Power's energy efficiency program for large commercial and industrial customers as a regulatory asset beginning January 1, 2011, but with an amortization period to be determined later by the IPUC.

In its June 1, 2011 general rate case filing, Idaho Power requested authorization to treat demand response incentive payments as power supply costs and establish a base or "normal" level of cost recovery of approximately $11.3 million for those demand response incentive payments in rates. The Idaho general rate case settlement stipulation approved by the IPUC in December 2011 provides that the $11.3 million of base level demand response incentive payments would be tracked as part of the Idaho PCA mechanism. The December 2011 IPUC general rate case settlement order also reset Idaho Power's energy efficiency rider rate at 4.0 percent of the sum of the monthly billed charges for the base rate components, a reduction from the 4.75 percent rider amount in effect prior to that date.

Langley Gulch Power Plant Ratemaking Treatment: On September 1, 2009, Idaho Power received pre-approval from the IPUC to include $396.6 million of construction costs in Idaho Power’s rate base when the Langley Gulch power plant achieves commercial operation. Idaho Power may request recovery of additional costs if they exceed $396.6 million, provided that the additional costs were reasonably and prudently incurred.

Oregon Regulatory Matters

2011 Oregon General Rate Case: On July 29, 2011, Idaho Power filed a general rate case and proposed rate schedules with the OPUC, Case No. UE 233. The filing requested a $5.8 million increase in annual Oregon jurisdictional revenues which, if approved, would result in a 14.7 percent overall average rate increase for customers in the Oregon jurisdiction. The filing requested an authorized rate of return on equity of 10.5 percent with an Oregon retail rate base of approximately $121.9 million, and a rate of return on capital of 8.17 percent. Idaho Power, the OPUC Staff, and other interested parties executed and filed a partial settlement stipulation with the OPUC on February 1, 2012, which resolves all matters in the general rate case other than the prudence of costs associated with pollution control investments at the Jim Bridger coal plant. The settlement stipulation provides for a return on equity of 9.9 percent and an overall rate of return of 7.757 percent. If the stipulation is approved by the OPUC, Idaho Power expects that new rates will become effective on March 1, 2012. As of the date of this report, Idaho Power is unable to determine the outcome of the proceeding.

2009 Oregon General Rate Case: On February 24, 2010, the OPUC approved a $5 million, or 15.4 percent, increase in base rates in the Oregon jurisdiction. The new rates were effective March 1, 2010, and were based on a return on equity of 10.175 percent and an overall rate of return of 8.061 percent. Idaho Power’s previously authorized rate of return in Oregon was 7.83 percent.

Advanced Metering Infrastructure (AMI)

The AMI project provides the means to automatically retrieve energy consumption information, eliminating manual meter reading expense. On February 12, 2009, the IPUC approved Idaho Power's application requesting a Certificate of Public Convenience and Necessity for the deployment of AMI technology and approval of accelerated depreciation for the existing metering equipment. The IPUC subsequently clarified that Idaho Power can expect to include in rate base the Idaho portion of prudent capital costs of deploying AMI as it is placed in service up to the capital cost commitment estimate of $70.9 million, plus certain costs that the company could not quantify with precision at the time of the application. The IPUC also clarified, as requested by Idaho Power, that it does not anticipate that the immediate savings derived from the implementation of AMI throughout Idaho Power's service territory will eliminate or wholly offset the increase in Idaho Power's revenue requirement caused by the authorized depreciation period.

On May 29, 2009, the IPUC approved annual recovery of $10.5 million, effective June 1, 2009. The order was based on Idaho Power's actual investment in AMI through the then-current date, annualized through December 31, 2009. The IPUC also allowed Idaho Power to begin three-year accelerated depreciation of the existing metering equipment on June 1, 2009. The order reflects annualized depreciation expense relating to AMI of $9.2 million. Actual depreciation expense recorded in 2011and 2010 was $10.6 million and $10.6 million respectively. On May 28, 2010, the IPUC approved Idaho Power's March 15, 2010 application requesting authorization to implement a $2.4 million base rate increase for identified customer classes to recover costs relating to the AMI project, with the rate increase effective June 1, 2010.

In the Oregon jurisdiction, the OPUC approved accelerated depreciation and recovery of existing meters located in Oregon over an 18-month period beginning January 2009. The approval increased both rates and depreciation expense by $0.8 million in 2009 and $0.4 million in 2010.

Idaho Power has completed the installation of substantially all smart meters associated with the AMI project. On February 15, 2012, Idaho Power filed an application with the IPUC requesting authority to decrease its Idaho-jurisdiction base rates by $10.6 million annually due to the removal of accelerated depreciation expense associated with non-AMI metering equipment. As of the date of this report, a determination and order from the IPUC is pending.

Depreciation Filings

In connection with a depreciation study authorized by Idaho Power and conducted by a third party, on February 15, 2012, Idaho Power filed an application with the IPUC seeking to institute revised depreciation rates for electric plant-in-service, based upon updated net salvage percentages and service life estimates for all plant assets, and adjust Idaho-jurisdictional base rates to reflect the revised depreciation rates. Idaho Power's application requested a $2.7 million increase in Idaho-jurisdictional base rates, with new rates effective June 1, 2012. As of the date of this report, a determination and order from the IPUC is pending.

Federal Open Access Transmission Tariff (OATT) Rates

In 2006, Idaho Power moved from a fixed rate to a formula rate for transmission service provided under its OATT, which allows transmission rates to be updated annually based on financial and operational data Idaho Power files with the FERC. Idaho Power's OATT rates submitted to the FERC in Idaho Power's three most recent annual OATT Final Informational Filings were as follows:

Applicable Period	OATT Rate (per KW-year)*
October 1, 2009 to September 30, 2010	$ 15.83
October 1, 2010 to September 30, 2011	$ 19.60
October 1, 2011 to September 30, 2012	$ 19.79

* In September 2010, Idaho Power made corrections to its OATT rates for the period beginning October 1, 2007 through September 30, 2010, which resulted in the issuance of a $0.5 million refund to transmission customers.

4. LONG-TERM DEBT

The following table summarizes long-term debt at December 31 (in thousands of dollars):

	2011	2010
First mortgage bonds:		
6.60% Series due 2011	$ —	$ 120,000
4.75% Series due 2012	100,000	100,000
4.25% Series due 2013	70,000	70,000
6.025% Series due 2018	120,000	120,000
6.15% Series due 2019	100,000	100,000
4.50% Series Due 2020	130,000	130,000
3.40% Series Due 2020	100,000	100,000
6% Series due 2032	100,000	100,000
5.50% Series due 2033	70,000	70,000
5.50% Series due 2034	50,000	50,000
5.875% Series due 2034	55,000	55,000
5.30% Series due 2035	60,000	60,000
6.30% Series due 2037	140,000	140,000
6.25% Series due 2037	100,000	100,000
4.85% Series due 2040	100,000	100,000
Total first mortgage bonds	1,295,000	1,415,000
Pollution control revenue bonds:		
5.15% Series due 2024(1)	49,800	49,800
5.25% Series due 2026(1)	116,300	116,300
Variable Rate Series 2000 due 2027	4,360	4,360
Total pollution control revenue bonds	170,460	170,460
American Falls bond guarantee	19,885	19,885
Milner Dam note guarantee	6,382	7,446
Unamortized premium/discount - net	(3,113)	(3,440)
Total Idaho Power outstanding(2)	$ 1,488,614	$ 1,609,351

(1) Humboldt County and Sweetwater County Pollution Control Revenue Bonds are secured by the first mortgage, bringing the total first mortgage bonds outstanding at December 31, 2011 to $1.461 billion.
(2) At December 31, 2011 and 2010, the overall effective cost of Idaho Power's outstanding debt was 5.43 percent and 5.53 percent, respectively.

At December 31, 2011, the maturities for the aggregate amount of long-term debt outstanding were (in thousands of dollars):

2012	2013	2014	2015	2016	Thereafter
$ 101,064	$ 71,064	$ 1,064	$ 1,064	$ 1,064	$ 1,316,407

Idaho Power Long-Term Financing

In May 2010, Idaho Power registered with the SEC the issuance of up to $500 million of first mortgage bonds and debt securities. On June 17, 2010, Idaho Power entered into a selling agency agreement with ten banks named in the agreement in connection with the potential issuance and sale from time to time of up to $500 million aggregate principal amount of first mortgage bonds. As of December 31, 2011, $300 million remained on Idaho Power's shelf registration for the issuance of first mortgage bonds and debt securities.

On March 2, 2011, Idaho Power repaid at maturity $120 million of first mortgage bonds using proceeds from first mortgage bonds issued in August 2010.

On August 30, 2010, Idaho Power issued $100 million of 3.40% First Mortgage Bonds, Secured Medium-Term Notes, Series I due 2020 and $100 million of 4.85% First Mortgage Bonds, Secured Medium-Term Notes, Series I due 2040 under the shelf registration statement.

Mortgage**:** As of December 31, 2011, Idaho Power could issue under its Indenture of Mortgage and Deed of Trust, dated as of October 1, 1937, between Idaho Power and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company) and R.G. Page, as Trustees (Stanley Burg, successor individual trustee) (Mortgage) approximately $1.3 billion of additional first mortgage bonds based on retired first mortgage bonds and total unfunded property additions. These amounts are further limited by the maximum amount of first mortgage bonds set forth in the Mortgage.

The Mortgage secures all bonds issued under the indenture equally and ratably, without preference, priority, or distinction. First mortgage bonds issued in the future will also be secured by the Mortgage. The lien of the indenture constitutes a first mortgage on all the properties of Idaho Power, subject only to certain limited exceptions including liens for taxes and assessments that are not delinquent and minor excepted encumbrances. Certain of the properties of Idaho Power are subject to easements, leases, contracts, covenants, workmen's compensation awards, and similar encumbrances and minor defects and clouds common to properties. The Mortgage does not create a lien on revenues or profits, or notes or accounts receivable, contracts or choses in action, except as permitted by law during a completed default, securities, or cash, except when pledged, or merchandise or equipment manufactured or acquired for resale. The Mortgage creates a lien on the interest of Idaho Power in property subsequently acquired, other than excepted property, subject to limitations in the case of consolidation, merger, or sale of all or substantially all of the assets of Idaho Power. The Mortgage requires Idaho Power to spend or appropriate 15 percent of its annual gross operating revenues for maintenance, retirement, or amortization of its properties. Idaho Power may, however, anticipate or make up these expenditures or appropriations within the five years that immediately follow or precede a particular year.

On February 17, 2010, Idaho Power entered into the Forty-fifth Supplemental Indenture, dated as of February 1, 2010, to the Mortgage for the purpose of increasing the maximum amount of first mortgage bonds issuable by Idaho Power from $1.5 to $2.0 billion. The amount issuable is also restricted by property, earnings, and other provisions of the Mortgage and supplemental indentures to the Mortgage. Idaho Power may amend the Mortgage and increase this amount without consent of the holders of the first mortgage bonds. The Mortgage requires that Idaho Power's net earnings be at least twice the annual interest requirements on all outstanding debt of equal or prior rank, including the bonds that Idaho Power may propose to issue. Under certain circumstances, the net earnings test does not apply, including the issuance of refunding bonds to retire outstanding bonds that mature in less than two years or that are of an equal or higher interest rate, or prior lien bonds.

5. NOTES PAYABLE

Credit Facilities

On October 26, 2011, Idaho Power entered into a amended and restated credit agreement, which amended and restated the existing $300 million credit facility. The new credit facility may be used for general corporate purposes and commercial paper backup. Idaho Power's credit facility consists of a revolving line of credit, through the issuance of loans and standby letters of credit, not to exceed the aggregate principal amount at any one time outstanding of $300 million, including swingline loans in an aggregate principal amount at any time outstanding not to exceed $30 million. Idaho Power has the right to request an increase in the aggregate principal amount of the facility to $450 million, respectively, subject to certain conditions. The credit facility matures on October 26, 2016, although Idaho Power has the right to request up to two one-year extensions of the credit agreement, in each case subject to certain conditions.

The interest rates for any borrowings under the facility is based on either (1) a floating rate that is equal to the highest of the prime rate, federal funds rate plus 0.5 percent, or LIBOR rate plus 1.0 percent, or (2) the LIBOR rate, plus, in each case, an applicable margin. The margin is based on Idaho Power's, senior unsecured long-term indebtedness credit rating by Moody's Investors Service, Inc., Standard and Poor's Ratings Services, and Fitch Rating Services, Inc., as set forth on a schedule to the credit agreement. The company pays a facility fee on the commitment based on the company's credit rating for senior unsecured long-term debt securities.

At December 31, 2011, no amounts were outstanding under Idaho Power's facility. At December 31, 2011, Idaho Power had regulatory authority to incur up to $450 million of short-term indebtedness. Balances and interest rates of short-term borrowings of commercial paper were as follows at December 31 (in thousands of dollars):

	Idaho Power	
	2011	**2010**
Commercial paper balances:		
At the end of year	$ —	$ —
Average during the year	$ —	$ 348

6. COMMON STOCK

Idaho Power Common Stock

In 2011 and 2010, IDACORP contributed $16 million and $50 million, respectively, of additional equity to Idaho Power. No additional shares of Idaho Power common stock were issued in exchange for the contributions.

Restrictions on Dividends

A covenant under Idaho Power’s credit facility requires Idaho Power to maintain a leverage ratio of consolidated indebtedness to consolidated total capitalization, as defined therein, of no more than 65 percent at the end of each fiscal quarter. Idaho Power’s ability to pay dividends on its common stock held by IDACORP is limited to the extent payment of such dividends would violate the covenants in their respective credit facilities or Idaho Power’s Revised Code of Conduct. At December 31, 2011, the leverage ratio for Idaho Power was 49 percent. Based on these restrictions, Idaho Power’s dividends are limited to $723 million at December 31, 2011. There are additional facility covenants, subject to exceptions, that prohibit certain mergers, acquisitions, and investments; restrict the creation of certain liens; and prohibit entering into any agreements restricting dividend payments to the company from any material subsidiary.

Idaho Power’s Revised Code of Conduct, approved by the IPUC on April 21, 2008, states that Idaho Power will not pay any dividends to IDACORP that will reduce Idaho Power’s common equity capital below 35 percent of its total adjusted capital without IPUC approval. Idaho Power’s articles of incorporation also contain restrictions on the payment of dividends on its common stock if preferred stock dividends are in arrears. Idaho Power has no preferred stock outstanding.

In addition to contractual restrictions on the amount and payment of dividends, the Federal Power Act prohibits the payment of dividends from "capital accounts." The term "capital accounts" is undefined in the Federal Power Act, but if conservatively interpreted could limit the payment of dividends by Idaho Power to the amount of Idaho Power's retained earnings.

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

7. STOCK-BASED COMPENSATION

Through its parent company IDACORP, Idaho Power has two share-based compensation plans -- the 2000 Long-Term Incentive and Compensation Plan (LTICP) and the 1994 Restricted Stock Plan (RSP). These plans are intended to align employee and shareholder objectives related to IDACORP's long-term growth.

The LTICP (for officers, key employees, and directors) permits the grant of nonqualified stock options, restricted stock, performance shares, and several other types of stock-based awards. The RSP permits only the grant of restricted stock or performance-based restricted stock. At December 31, 2011, the maximum number of shares available under the LTICP and RSP were 1,503,861 and 15,796, respectively.

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

Performance-based restricted stock awards have three-year vesting periods and entitle the recipients to voting rights. Unvested shares are restricted as to disposition, subject to forfeiture under certain circumstances, and subject to meeting specific performance conditions. Based on the attainment of the performance conditions, the ultimate award can range from zero to 150 percent of the target award. Dividends are accrued and paid out only on shares that eventually vest.

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

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

	Number of Shares	**Weighted-Average Grant Date Fair Value**
Nonvested shares at January 1, 2011	329,501	$26.35
Shares granted	135,016	30.30
Shares forfeited	(11,451)	27.32
Shares vested	(115,883)	25.28
Nonvested shares at December 31, 2011	337,183	$26.40

The total fair value of shares vested during the years ended December 31, 2011 and 2010, was $4.1 million and $3.3 million, respectively. At December 31, 2011, Idaho Power had $4 million of total unrecognized compensation cost related to nonvested share-based compensation that was expected to vest. These costs are expected to be recognized over a weighted-average period of 1.68 years. Idaho Power uses IDACORP's original issue and/or treasury shares for these awards.

In 2011, a total of 11,920 shares were awarded to directors at a grant date fair value of $37.74 per share. Directors elected to defer receipt of 5,960 of these shares, which are being held as deferred stock units with dividend equivalents reinvested in additional stock units.

Stock Options: No stock options have been granted since 2006. The remaining unexercised stock option awards were granted with exercise prices equal to the market value of the stock on the date of grant, with a term of 10 years from the grant date and a five-year vesting period. The fair value of each option was amortized into compensation expense using graded vesting and, as of December 31, 2011, all compensation costs have been recognized. Idaho Power uses IDACORP's uses original issue and/or treasury shares to satisfy exercised options.

Idaho Power's stock option transactions are summarized below.

	Number of Shares	Weighted-Average Exercise Price	Weighted Average Remaining Contractual Term (Years)	Aggregate Intrinsic Value (000s)
Outstanding at December 31, 2010	202,634	$ 38.05	1.13	$ 314
Exercised	(90,945)	35.54		
Expired	(102,233)	39.89		
Outstanding at December 31, 2011	9,456	$ 33.67	1.58	$ 83
Vested and exercisable at December 31, 2011	9,456	$ 33.67	1.58	$ 83

The following table presents information about options vested and exercised (in thousands of dollars):

	2011	2010
Fair value of options vested	$ —	$ 96
Intrinsic value of options exercised	535	1,475
Cash received from exercises	3,838	5,394
Tax benefits realized from exercises	209	577

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

	2011	2010
Compensation cost	$ 4,082	$ 3,489
Income tax benefit	1,596	1,364

No equity compensation costs have been capitalized.

8. COMMITMENTS

Purchase Obligations

At December 31, 2011, Idaho Power had the following long-term commitments relating to purchases of energy, capacity, transmission rights, and fuel (in thousands of dollars):

	2012	2013	2014	2015	2016	Thereafter
Cogeneration and power production	$ 165,693	$ 196,261	$ 209,295	$ 214,960	$ 218,220	$ 3,687,810
Power and transmission rights	10,772	4,243	3,188	2,210	1,879	4,401

Fuel	79,138	64,852	66,309	22,661	8,909	98,212

As of December 31, 2011, Idaho Power had signed agreements to purchase energy from 119 CSPP facilities with contracts ranging from one to 35 years. Ninety-six of these facilities, with a combined nameplate capacity of 606 MW, were on-line at the end of 2011; the other 23 facilities under contract, with a combined nameplate capacity of 383 MW, are projected to come on-line by year end 2014. The majority of the new facilities will be wind resources which will generate on an intermittent basis. During 2011, Idaho Power purchased 1,495,108 megawatt-hours (MWh) from these projects at a cost of $90 million, resulting in a blended price of $60.36 per MWh. Idaho Power purchased 910,429 MWh at a cost of $55 million in 2010.

In addition, IPC has the following long-term commitments for lease guarantees, equipment, maintenance and services, and industry related fees (in thousands of dollars):

	2012	2013	2014	2015	2016	Thereafter
Operating leases	$ 2,005	$ 2,875	$ 2,768	$ 2,199	$ 1,203	$ 15,711
Equipment, maintenance, and service agreements	38,553	15,271	6,169	4,897	3,700	8,254
FERC and other industry-related fees	12,391	12,031	9,745	9,745	6,596	32,981

IPC's expense for operating leases was approximately $5.2 million in 2011 and $3.3 million in 2010.

Guarantees

Idaho Power has agreed to guarantee a portion of the performance of reclamation activities and obligations at BCC, of which IERCo owns a one-third interest. This guarantee, which is renewed each December, was $63 million at December 31, 2011, representing IERCo's one-third share of BCC's total reclamation obligation of $189 million. BCC has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. As of December 31, 2011, the value of the reclamation trust fund totaled $80 million. BCC periodically assesses the adequacy of the reclamation trust fund and its estimate of future reclamation costs. To ensure that the reclamation trust fund maintains adequate reserves, BCC has the ability to add a per-ton surcharge to coal sales. Starting in 2010, BCC began applying a nominal surcharge to coal sales in order to maintain adequate reserves in the reclamation trust fund. Because of the existence of the fund and the ability to apply a per-ton surcharge, the estimated fair value of this guarantee is minimal.

Idaho Power enters into financial agreements and power purchase and sale agreements that include indemnification provisions relating to various forms of claims or liabilities that may arise from the transactions contemplated by these agreements. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnification provisions cannot be reasonably estimated. Idaho Power periodically evaluates the likelihood of incurring costs under such indemnities based on their historical experience and the evaluation of the specific indemnities. As of December 31, 2011, management believes the likelihood is remote that Idaho Power would be required to perform under such indemnification provisions or otherwise incur any significant losses with respect to such indemnification obligations. Idaho Power has not recorded any liability on their respective consolidated balance sheets with respect to these indemnification obligations.

9. CONTINGENCIES

Idaho Power has in the past and expects in the future to become involved in various claims, controversies, disputes, and other contingent matters, including the items described in this Note 9. Some of these claims, controversies, disputes, and other contingent matters involve litigation and regulatory or other contested proceedings. Idaho Power intends to vigorously protect and defend their interests and pursue their rights. However, the ultimate resolution and outcome of litigation and regulatory proceedings is inherently difficult to determine, particularly where (a) the remedies or penalties sought are indeterminate, (b) the proceedings are in the early stages or the substantive issues have not been well developed, or (c) the matters involve complex or novel legal theories or a large number of parties. In accordance with applicable accounting guidance, Idaho Power establishes an accrual for legal proceedings when those matters proceed to a stage where they present loss contingencies that are both probable and reasonably estimable. In such cases, there may be a possible exposure to loss in excess of any amounts accrued. Idaho Power monitors those matters for developments that could affect the likelihood of a loss and the accrued amount, if any, thereof, and adjust the amount as appropriate. If the loss contingency at issue is not both probable and reasonably estimable, Idaho Power does not establish an accrual and the matter will continue to be monitored for any developments that would make the loss contingency both probable and reasonably estimable. As of the date of this report, Idaho Power's accruals for legal proceedings are not material to their financial statements as a whole; however, future accruals could be material in a given period. Idaho Power's determination is based on currently available information, and estimates presented in financial statements and other financial disclosures involve significant judgment and may be subject to significant uncertainty. As available information changes, the matters for which Idaho Power is able to estimate the loss may change, and the estimates themselves may change.

For certain of those matters described in this report for which Idaho Power has determined a loss contingency may, in the future, be at least reasonably possible, Idaho Power has stated that they are unable to estimate the possible loss or a range of possible loss that may result from those matters. Depending on a range of factors, such as the complexity of the facts, the unique nature of the legal theories, the pace of discovery, the timing of court decisions, and the adverse party's willingness to negotiate towards a resolution, it may be months or years after the filing of a case before Idaho Power may be in a position to estimate the possible loss or range of possible loss for those matters.

Given the substantial or indeterminate amounts sought in certain of the matters described below, and the inherent unpredictability of such matters, an adverse outcome in certain of these matters could have a material adverse effect on Idaho Power's financial condition, results of operations, or cash flows in particular quarterly or annual periods. For matters that affect Idaho Power’s operations, Idaho Power intends to seek, to the extent permissible and appropriate, recovery of incurred costs through the ratemaking process.

Western Energy Proceedings

High prices for electricity, energy shortages, and blackouts in California and in western wholesale markets during 2000 and 2001 caused numerous purchasers of electricity in those markets to initiate proceedings seeking refunds or other forms of relief and the FERC to initiate its own investigations. Some of these proceedings remain pending before the FERC or are on appeal to the United States Court of Appeals for the Ninth Circuit (Ninth Circuit). Except as to the matters described below under “Pacific Northwest Refund,” Idaho Power and IDACORP Energy (IE) believe that settlement releases they have obtained will restrict potential claims that might result from the disposition of the pending Ninth Circuit review petitions and predict that these matters will not have a material adverse effect on their consolidated financial positions, results of operations, or cash flows.

Pacific Northwest Refund: On July 25, 2001, the FERC issued an order establishing a proceeding to determine whether there may have been unjust and unreasonable charges for spot market sales in the Pacific Northwest during the period December 25, 2000 through June 20, 2001, because the spot market in the Pacific Northwest was affected by the dysfunction in the California market. During that period, Idaho Power or IE both sold and purchased electricity in the Pacific Northwest. In 2003, the FERC terminated the proceeding and declined to order refunds, but in 2007 the Ninth Circuit issued an opinion, in *Port of Seattle, Washington v. FERC*, remanding to the FERC the orders that declined to require refunds. The Ninth Circuit's opinion instructed the FERC to consider whether evidence of market manipulation would have altered the agency's conclusions about refunds and directed the FERC to include sales originating in the Pacific Northwest to the California Department of Water Resources (CDWR) in the scope of the proceeding. The Ninth Circuit officially returned the case to the FERC on April 16, 2009. On October 3, 2011, the FERC issued its order on remand. The FERC ordered that the record be re-opened to permit parties seeking refunds to submit seller-specific evidence in support of their claims for sales made during the period confined to December 25, 2000 through June 20, 2001. The seller-specific claims must show that a seller engaged in unlawful market activity with a causal connection to have directly affected the negotiation of the specific contract or contracts to which the seller was a party. Neither claims of general dysfunction in the California markets nor in the Pacific Northwest market will be sufficient to support claims. While directing a trial-type hearing, the FERC also directed that the hearings be held in abeyance so that the matter may be presented to a settlement judge. On November 2, 2011, each of the City of Seattle, Washington, the City of Tacoma, Washington, the Port of Seattle, and the California Parties (consisting of the California Attorney General and the California Public Utilities Commission) filed requests for rehearing, seeking to expand the scope of the October 3, 2011 order. The designated settlement judge has met with the parties and convened a settlement conference to establish settlement procedures. The FERC's Chief Administrative Law Judge memorialized certain settlement procedures to which the parties agreed in an order issued on November 23, 2011.

IE and Idaho Power intend to continue to defend their positions in the Pacific Northwest refund proceedings vigorously. As of the date of this report, it is difficult to predict the outcome of this matter. Idaho Power does not believe that claims conforming to the requirements of the FERC's October 3, 2011 order have been submitted, and the FERC's order remains subject to rehearing and reconsideration. Idaho Power and IE are unable to predict when and how the FERC will act on the rehearing requests, which contracts would be subject to refunds, whether the FERC will order refunds, or how the refunds would be calculated. As a result of these factors, as of the date of this report Idaho Power and IE are unable to estimate the reasonably possible loss or range of losses that Idaho Power or IE could incur as a result of this matter. However, based on the status of settlement discussions with one party to the proceedings, for that portion of the matter Idaho Power reserved for a contingent liability an amount immaterial to Idaho Power's financial statements in the fourth quarter of 2011.

EPA Notice of Violation - Boardman

In September 2010, the U.S. Environmental Protection Agency (EPA) issued a Notice of Violation to Portland General Electric Company (PGE), alleging that PGE had violated the New Source Performance Standards (NSPS) and operating permit requirements under the Clean Air Act (CAA) as a result of modifications made to the Boardman coal-fired plant in 1998 and 2004. PGE is the operator of the Boardman plant, and Idaho Power has a 10 percent ownership interest in the plant. The Notice of Violation states the maximum civil penalties the EPA is authorized to impose under the CAA for violations of the NSPS (which range from $25,000 to $37,500 per day), but it does not impose any penalties or specify the amount of any proposed penalties with respect to the alleged violations. It is difficult to meaningfully predict the eventual outcome of this matter given the complexity of the environmental statutes and claims cited in the Notice of Violation and the matters at issue, the unspecified nature of the penalty or other remedy sought, and the absence of factual information given the early stage of the proceedings. As of the date of this report, based on available information and the status of this matter, Idaho Power is unable to estimate the reasonably possible loss or range of losses that Idaho Power could incur as a result of this matter. However, PGE, the plant operator, has stated that based on its understanding of the penalties authorized under the CAA, the maximum penalty that could be imposed for the alleged violations is approximately $60 million, with Idaho Power's share of any such penalty being limited to 10 percent of the amount ultimately assessed, if any.

Water Rights - Snake River Basin Adjudication

Idaho Power holds water rights, acquired under applicable state law, for its hydroelectric projects. In addition, Idaho Power holds water rights for domestic, irrigation, commercial, and other necessary purposes related to project lands and other holdings within the states of Idaho and Oregon. Idaho Power's water rights for power generation are, to varying degrees, subordinated to future upstream appropriations for irrigation and other authorized consumptive uses.

Over time, increased irrigation development and other consumptive uses within the Snake River watershed led to a reduction in flows of the Snake River. In the late 1970's and early 1980's these reduced flows resulted in a conflict between the exercise of Idaho Power's water rights at certain hydroelectric projects on the Snake River and upstream consumptive diversions. The Swan Falls Agreement, signed by Idaho Power and the State of Idaho on October 25, 1984, resolved the conflict and provided a level of protection for Idaho Power's hydropower water rights at specified projects on the Snake River through the establishment of minimum stream flows and an administrative process governing future development of water rights that may affect those minimum stream flows. In 1987, Congress enacted legislation directing the FERC to issue an order approving the Swan Falls settlement together with a finding that the agreement was neither inconsistent with the terms and conditions of Idaho Power's project licenses nor the Federal Power Act. The FERC entered an order implementing the legislation on March 25, 1988.
The Swan Falls Agreement provided that the resolution and recognition of Idaho Power's water rights together with the State Water Plan provided a sound comprehensive plan for management of the Snake River watershed. The Swan Falls Agreement also recognized, however, that in order to effectively manage the waters of the Snake River basin, a general adjudication to determine the nature, extent, and priority of the rights of all water uses in the basin was necessary. Consistent with that recognition, in 1987 the State of Idaho initiated the Snake River Basin Adjudication (SRBA), and pursuant to the commencement order issued by the SRBA

court that same year, all claimants to water rights within the basin were required to file water rights claims in the SRBA. Idaho Power has filed claims to its water rights and has been actively participating in the SRBA since its commencement. Questions concerning the effect of the Swan Falls Agreement on Idaho Power's water rights claims, including the nature and extent of the subordination of Idaho Power's rights to upstream uses, resulted in the filing of litigation in the SRBA in 2007 between Idaho Power and the State of Idaho. This litigation was resolved by the Framework Reaffirming the Swan Falls Settlement (Framework) signed by Idaho Power and the State of Idaho on March 25, 2009. In that Framework, the parties acknowledged that the effective management of Idaho's water resources remains critical to the public interest of the State of Idaho by sustaining economic growth, maintaining reasonable electric rates, protecting and preserving existing water rights, and protecting water quality and environmental values. The Framework further provided that the State of Idaho and Idaho Power would cooperate in exploring approaches to resolve issues of mutual concern relating to the management of Idaho's water resources. Idaho Power continues to work with the State of Idaho and other interested parties on these issues.

One such issue involves the management of the Eastern Snake Plain Aquifer (ESPA), a large underground aquifer in southeastern Idaho that is hydrologically connected to the Snake River. House Concurrent Resolution No. 28, adopted by the Idaho Legislature in 2007, directed the Idaho Water Resource Board to pursue the development of a comprehensive management plan for the ESPA, to include measures that would enhance aquifer levels, springs, and river flows on the eastern Snake River plain to the benefit of both agricultural development and hydropower generation. In May of 2007, the Idaho Water Resource Board appointed an advisory committee, charged with the responsibility of developing a management plan for the ESPA. Idaho Power was a member of that committee. In January 2009, the Idaho Water Resource Board, based on the committee's recommendations, adopted a Comprehensive Aquifer Management Plan (CAMP) for the ESPA. The Idaho Legislature approved the CAMP that same year. Idaho Power is a member of the CAMP Implementation Committee and continues to work with the Idaho Water Resource Board, other stakeholders, and the Idaho Legislature in exploring opportunities for implementation of the CAMP management plan.

Idaho Power also continues its active participation in the SRBA in seeking to ensure that its water rights are protected and that the operation of its hydroelectric projects is not adversely impacted. While Idaho Power cannot predict the outcome, Idaho Power does not anticipate any material modification of its water rights as a result of the SRBA process.

Other Legal Proceedings

From time to time Idaho Power is party to legal claims, actions, and proceedings in addition to those discussed above. However, as of the date of this report the company believes that resolution of these matters will not have a material adverse effect on the consolidated financial positions, results of operations, or cash flows.

10. BENEFIT PLANS

Pension Plans

Idaho Power has a noncontributory defined benefit pension plan covering most employees. The benefits under the plan are based on years of service and the employee’s final average earnings. Idaho Power’s policy is to fund, with an independent corporate trustee, at least the minimum required under the Employee Retirement Income Security Act of 1974 (ERISA) but not more than the maximum amount deductible for income tax purposes. In 2011 and 2010 Idaho Power elected to contribute more than the minimum required amounts in order to bring the plan to a more funded position, to reduce future required contributions, and to reduce Pension Benefit Guaranty Corporation premiums. The market-related value of assets for the plan is equal to the fair value of the assets. Fair value is determined by utilizing publicly quoted market values and independent pricing services depending on the nature of the asset, as reported by the trustee/custodian of the plan.

In addition, Idaho Power has a nonqualified, deferred compensation plan for certain senior management employees and directors called the Senior Management Security Plan (SMSP). At December 31, 2011 and 2010, approximately $41.2 million and $46.2 million, respectively, of life insurance policies and investments in marketable securities, all of which are held by a trustee, were designated to satisfy the projected benefit obligation of the plan but do not qualify as plan assets in the actuarial computation of the funded status.

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

	Pension Plan		SMSP	
	2011	**2010**	**2011**	**2010**
Change in benefit obligation:				
Benefit obligation at January 1	$ 569,934	$ 506,744	$ 59,126	$ 52,719
Service cost	20,478	17,671	1,950	1,541
Interest cost	30,322	29,119	3,094	3,004
Actuarial loss	55,535	35,909	4,251	5,186
Benefits paid	(20,830)	(19,509)	(3,378)	(3,324)
Benefit obligation at December 31	655,439	569,934	65,043	59,126
Change in plan assets:				
Fair value at January 1	397,003	313,474	—	—
Actual return on plan assets	(4,592)	43,038	—	—
Employer contributions	18,500	60,000	—	—
Benefits paid	(20,830)	(19,509)	—	—
Fair value at December 31	390,081	397,003	—	—
Funded status at end of year	$ (265,358)	$ (172,931)	$ (65,043)	$ (59,126)
Amounts recognized in the statement of financial position consist of:				
Other current liabilities	$ —	$ —	$ (3,496)	$ (3,289)
Noncurrent liabilities	(265,358)	(172,931)	(61,547)	(55,837)
Net amount recognized	$ (265,358)	$ (172,931)	$ (65,043)	$ (59,126)
Amounts recognized in accumulated other comprehensive income consist of:				
Net loss	$ 245,632	$ 161,855	$ 21,799	$ 18,840
Prior service cost	1,335	1,855	1,502	1,744
Subtotal	246,967	163,710	23,301	20,584
Less amount recorded as regulatory asset	(246,967)	(163,710)	—	—
Net amount recognized in accumulated other comprehensive income	$ —	$ —	$ 23,301	$ 20,584
Accumulated benefit obligation	$ 549,503	$ 482,448	$ 59,836	$ 54,213

The following table shows the components of net periodic benefit cost for these plans (in thousands of dollars):

	Pension Plan		SMSP	
	2011	**2010**	**2011**	**2010**
Service cost	$ 20,478	$ 17,671	$ 1,950	$ 1,541
Interest cost	30,322	29,119	3,094	3,004
Expected return on assets	(32,322)	(26,463)	—	—
Amortization of net loss	8,673	7,675	1,293	931
Amortization of prior service cost	519	650	242	233
Net periodic pension cost	27,670	28,652	6,579	5,709
Adjustment to cost recognized due to the effects of regulation(1)	6,662	(24,104)	—	—
Net periodic benefit cost recognized for financial reporting	$ 34,332	$ 4,548	$ 6,579	$ 5,709

(1) Net periodic benefit costs for the pension plan are recognized based on the authorization of each regulatory jurisdiction Idaho Power operates within. Under IPUC order, income statement recognition of pension plan costs is deferred until costs are recovered through rates. See Note 3 for information on Idaho Power's 2011 Idaho pension rate order, which increased Idaho-jurisdiction recovery to $17.1 million annually, effective June 1, 2011, and also for information on Idaho Power's sharing mechanism, which resulted in additional Idaho pension amortization of $20.3 million in 2011.

In 2012, Idaho Power expects to recognize as components of net periodic benefit cost $15.9 million from amortizing amounts recorded in accumulated other comprehensive income (or as a regulatory asset for the pension plan) as of December 31, 2011, relating to the pension and SMSP plans. This amount consists of $13.9 million of amortization of net loss and $0.3 million of amortization of prior service cost for the pension plan, and $1.5 million of amortization of net loss and $0.2 million of amortization of prior service cost for the SMSP.

The following table summarizes the expected future benefit payments of these plans (in thousands of dollars):

	2012	2013	2014	2015	2016	2017-2021
Pension Plan	$ 22,360	$ 24,001	$ 25,684	$ 27,597	$ 29,761	$ 186,450
SMSP	3,578	3,707	3,899	4,063	4,084	22,797

As of December 31, 2011, Idaho Power's minimum required contributions to the defined benefit pension plan are estimated to be approximately $34 million in 2012, $44 million in 2013, $44 million in 2014, $42 million in 2015, and $42 million in 2016. Idaho Power may elect to make contributions earlier than the required dates.

Postretirement Benefits

Idaho Power maintains a defined benefit postretirement benefit plan (consisting of health care and death benefits) that covers all employees who were enrolled in the active group plan at the time of retirement as well as their spouses and qualifying dependents. Retirees hired on or after January 1, 1999 have access to the standard medical option at full cost, with no contribution by Idaho Power. Benefits for employees who retire after December 31, 2002 are limited to a fixed amount, which has limited the growth of Idaho Power's future obligations under this plan.

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

	2011	2010
Change in accumulated benefit obligation:		
Benefit obligation at January 1	$ 68,048	$ 62,647
Service cost	1,323	1,276
Interest cost	3,434	3,578
Actuarial loss	(2,850)	3,291
Benefits paid(1)	(2,968)	(3,373)
Plan amendments	(318)	629
Benefit obligation at December 31	66,669	68,048
Change in plan assets:		
Fair value of plan assets at January 1	33,176	30,892
Actual return on plan assets	1,065	3,381
Employer contributions	628	2,276
Benefits paid(1)	(2,968)	(3,373)
Fair value of plan assets at December 31	31,901	33,176
Funded status at end of year (included in noncurrent liabilities)	$ (34,768)	$ (34,872)

(1) Benefits paid are net of $3,405 and $2,971 of plan participant contributions, and $444 and $415 of Medicare Part D subsidy receipts for 2011 and 2010, respectively.

Amounts recognized in accumulated other comprehensive income consist of the following (in thousands of dollars):

	2011	2010
Net loss	$ 14,112	$ 15,963
Prior service credit	(323)	(426)
Transition obligation	2,040	4,080
Subtotal	15,829	19,617
Less amount recognized in regulatory assets	(15,536)	(19,032)
Less amount included in deferred tax assets	(293)	(585)
Net amount recognized in accumulated other comprehensive income	$ —	$ —

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

	2011	2010
Service cost	$ 1,323	$ 1,276
Interest cost	3,434	3,578
Expected return on plan assets	(2,641)	(2,503)
Amortization of net loss	577	562
Amortization of prior service cost	(421)	(482)
Amortization of unrecognized transition obligation	2,040	2,040
Net periodic postretirement benefit cost	$ 4,312	$ 4,471

In 2012, Idaho Power expects to recognize as components of net periodic benefit cost $2.2 million from amortizing amounts recorded in accumulated other comprehensive income as of December 31, 2011 relating to the postretirement benefit plan. This amount consists of $(0.4) million of prior service cost, $0.6 million of net loss, and $2.0 million of transition obligation.

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

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

	2012	2013	2014	2015	2016	2017-2021
Expected benefit payments	$ 4,176	$ 4,261	$ 4,415	$ 4,543	$ 4,620	$ 23,849
Expected Medicare Part D subsidy receipts	478	524	563	612	671	4,441

Plan Assumptions

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

	Pension Plan		SMSP		Postretirement Benefits	
	2011	2010	2011	2010	2011	2010
Discount rate	4.90%	5.40%	5.10%	5.40%	5.05%	5.40%
Rate of compensation increase(1)	4.35%	4.50%	4.50%	4.50%	—	—
Medical trend rate	—	—	—	—	7.0%	7.5%
Dental trend rate	—	—	—	—	5%	5%
Measurement date	12/31/2011	12/31/2010	12/31/2011	12/31/2010	12/31/2011	12/31/2010

(1) The 2011 rate of compensation increase assumption for the pension plan includes an inflation component of 2.75% plus a 1.60% composite merit increase component that is based on employees' years of service. Merit salary increases are assumed to be 8.0% for employees in their first year of service and scale down to 0% for employees in the fortieth year of service and beyond.

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

	Pension Plan		SMSP		Postretirement Benefits	
	2011	2010	2011	2010	2011	2010
Discount rate	5.40%	5.90%	5.40%	5.90%	5.40%	5.90%
Expected long-term rate of return on assets	8.25%	8.25%	—	—	8.25%	8.25%
Rate of compensation increase	4.50%	4.50%	4.50%	4.50%	—	—
Medical trend rate	—	—	—	—	7.0%	7.5%
Dental trend rate	—	—	—	—	5.0%	5.0%

The assumed health care cost trend rate used to measure the expected cost of health benefits covered by the postretirement plan was 7.0 percent and 7.5 percent in 2011 and 2010, respectively. The assumed health care cost trend rate for 2011 is assumed to decrease gradually to 4.9 percent by 2083. The assumed dental cost trend rate used to measure the expected cost of dental benefits covered by the plan was 5.0 percent in both 2011 and 2010. The assumed dental cost trend rate for 2011 is assumed to decrease gradually to 4.9 percent by 2083. A one percentage point change in the assumed health care cost trend rate would have the following effects at

December 31, 2011 (in thousands of dollars):

	One-Percentage-Point Increase	One-Percentage-Point Decrease
Effect on total of cost components	$ 342	$ (255)
Effect on accumulated postretirement benefit obligation	2,939	(2,300)

Plan Assets

Pension Asset Allocation Policy: The target allocation and actual allocations at December 31, 2011 for the pension asset portfolio by asset class is set forth below.

Asset Class	Target Allocation	Actual Allocation 31-Dec-11
Debt securities	24%	25%
Equity securities	54%	54%
Real estate	6%	6%
Other plan assets	16%	15%
Total	100%	100%

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

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

The three major goals in Idaho Power's asset allocation process are to:

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

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

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

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

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

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

If the inputs used to measure the securities fall within different levels of the hierarchy, the categorization is based on the lowest level input (Level 3 being the lowest) that is significant to the fair value measurement of the security. The following table sets forth by level within the fair value hierarchy a summary of the plans' investments measured at fair value on a recurring basis at December 31, 2011 (in thousands of dollars):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Assets at December 31, 2011				
Pension assets:				
Cash and cash equivalents	$ 6,141	$ —	$ —	$ 6,141
Short-term bonds	—	23,443	—	23,443
Long-term bonds	—	74,658	—	74,658
Equity Securities: Large-Cap	51,780	—	—	51,780
Equity Securities: Mid-Cap	17,961	14,002	—	31,963
Equity Securities: Small-Cap	31,825	—	—	31,825
Equity Securities: Micro-Cap	16,087	—	—	16,087
Equity Securities: International	30,444	32,118	—	62,562
Equity Securities: Emerging Markets	1,745	15,112	—	16,857
Real estate	—	—	25,119	25,119
Private market investments	—	—	27,786	27,786
Commodities funds	2,929	18,931	—	21,860
Total pension assets	$ 158,912	$ 178,264	$ 52,905	$ 390,081
Postretirement assets(2)	$ —	$ 31,901	$ —	$ 31,901
Assets at December 31, 2010				
Pension assets:				
Cash and cash equivalents	$ 16,837	$ —	$ —	$ 16,837
Short-term bonds(1)	—	30,241	—	30,241
Core bonds(1)	—	43,156	—	43,156
Equity Securities: Large-Cap	58,961	—	—	58,961
Equity Securities: Mid-Cap	17,775	14,261	—	32,036
Equity Securities: Small-Cap	35,278	—	—	35,278
Equity Securities: Micro-Cap	17,422	—	—	17,422
Equity Securities: International	32,655	33,874	—	66,529
Equity Securities: Emerging Markets	2,199	18,241	—	20,440
Real estate	—	—	22,069	22,069
Private market investments	—	—	29,932	29,932
Commodities funds	3,406	20,696	—	24,102

Total pension assets	$ 184,533	$ 160,469	$ 52,001	$ 397,003
Postretirement assets(2)	$ —	$ 33,176	$ —	$ 33,176

(1) Subsequent to the issuance of the 2010 consolidated financial statements, Idaho Power determined these investments had previously been incorrectly categorized as Level 1 investments within the fair value hierarchy. As a result, the 2010 amounts have been restated to reflect the investments as Level 2.

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

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

	Private Equity	**Real Estate**	**Total**
Beginning balance - January 1, 2010	$ 20,202	$ 20,783	$ 40,985
Realized losses	—	(47)	(47)
Unrealized gains	1,284	2,211	3,495
Purchases, issuances, and settlements, net	8,446	(878)	7,568
Ending balance - December 31, 2010	29,932	22,069	52,001
Realized gains	—	598	598
Realized losses	(133)	—	(133)
Unrealized gains	1,425	1,854	3,279
Purchases, issuances, and settlements, net	(3,438)	598	(2,840)
Ending balance - December 31, 2011	$ 27,786	$ 25,119	$ 52,905

Fair Value Measurement of Level 2 and Level 3 Plan Asset Inputs

Level 2 Bonds, Equity Securities, and Level 2 Commodities: These investments represent U.S. government and agency bonds, corporate bonds, and commingled funds consisting of publicly traded equity securities or exchange-traded commodity contracts and other contractual claims to commodity holdings. The U.S. government and agency bonds, as well as the corporate bonds, are not traded on an exchange and are valued utilizing quoted prices for similar assets or liabilities in active markets. The commingled funds themselves are not publicly traded, and therefore no publicly quoted market price is readily available. The value of these investments is calculated by the custodian for the fund company on a monthly basis, and is based on market prices of the assets held by the commingled fund divided by the number of fund shares outstanding.

Level 3 Real Estate: Real estate holdings represent investments in open-ended commingled real estate funds. As the property interests held in these real estate funds are not frequently traded, establishing the market value of the property interests held by the fund, and the resulting unit value of fund shareholders, is based on unobservable inputs including property appraisals by the fund company, property appraisals by independent appraisal firms, analysis of the replacement cost of the property, discounted cash flows generated by property rents and changes in property values, and comparisons with sale prices of similar properties in similar markets. These open-ended real estate funds also furnish annual audited financial statements that are also used to further validate the information provided.

Level 3 Private Market Investments: Private market investments represent two categories: fund of hedge funds and venture capital funds. These funds are valued by the fund company based on the estimated fair value of the underlying fund holdings divided by the fund shares outstanding. Some hedge fund strategies utilize securities with readily available market prices, while others utilize less liquid investment vehicles that are valued based on unobservable inputs including cost, operating results, recent funding activity, or comparisons with similar investment vehicles. Venture capital fund investments are valued by the fund company based on estimated fair value of the underlying fund holdings divided by the fund shares outstanding. Some venture capital investments have progressed to the point that they have readily available exchange-based market valuations. Early stage venture investments are valued based on unobservable inputs including cost, operating results, discounted cash flows, the price of recent funding events, or pending offers from other viable entities. These private market investments furnish annual audited financial statements that are also used to further validate the information provided.

There were no material changes in valuation techniques or inputs during the years ended December 31, 2011 and 2010.

Employee Savings Plan

Idaho Power has a defined contribution plan designed to comply with Section 401(k) of the Internal Revenue Code and which covers substantially all employees (the Employee Savings Plan). Idaho Power matches specified percentages of employee contributions to the plan. Matching annual contributions were $6 million in 2011 and $5 million in 2010.

Post-employment Benefits

Idaho Power provides certain benefits to former or inactive employees, their beneficiaries, and covered dependents after employment but before retirement. These benefits include salary continuation, health care and life insurance for those employees found to be disabled under Idaho Power's disability plans, and health care for surviving spouses and dependents. Idaho Power accrues a liability for such benefits. The post employment benefit amounts included in other deferred credits on Idaho Power's consolidated balance sheet at December 31, 2011 and 2010 are $3.8 million and $4.5 million, respectively.

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

The following table presents the major classifications of Idaho Power's utility plant in service, annual depreciation provisions as a percent of average depreciable balance, and accumulated provision for depreciation for the years 2011 and 2010 (in thousands of dollars):

	2011		2010	
	Balance	**Avg Rate**	**Balance**	**Avg Rate**
Production	$ 1,832,287	2.22%	$ 1,792,305	2.23%
Transmission	871,784	2.06%	855,202	2.03%
Distribution	1,434,925	3.12%	1,377,239	3.13%
General and Other	327,877	7.32%	307,308	7.41%
Total in service	4,466,873	2.83%	4,332,054	2.84%
Accumulated provision for depreciation	(1,840,782)		(1,771,655)	
In service - net	$ 2,626,091		$ 2,560,399	

In 2010, Idaho Power sold $19 million of transmission-related assets to PacifiCorp at book value.

Idaho Power has interests in three jointly-owned generating facilities included in the table above. Under the joint operating agreements, each participating utility is responsible for financing its share of construction, operating, and leasing costs. Idaho Power's proportionate share of related fuel expenses as well as direct operation and maintenance expenses applicable to the projects is included in the Consolidated Statements of Income. These facilities, and the extent of Idaho Power's participation, were as follows at December 31, 2011 (in thousands of dollars):

Name of Plant	**Location**	**Utility Plant in Service**	**Construction Work in Progress**	**Accumulated Provision for Depreciation**	**Ownership %**	**MW[(1)]**
Jim Bridger Units 1-4	Rock Springs, WY	$539,294	$8,334	$276,375	33	771

Boardman	Boardman, OR	79,714	940	53,843	10	64
Valmy Units 1 and 2	Winnemucca, NV	350,582	7,352	202,811	50	284

(1) Idaho Power's share of nameplate capacity.

IERCo, Idaho Power's wholly-owned subsidiary, is a joint venturer in BCC. Idaho Power's coal purchases from the joint venture were $65 million and $76 million in 2011 and 2010, respectively.

Idaho Power has contracts to purchase the energy from four PURPA qualified facilities that are 50 percent owned by Ida-West. Idaho Power's power purchases from these facilities were $9 million and $8 million in 2011 and 2010, respectively.

12. ASSET RETIREMENT OBLIGATIONS (ARO)

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

Idaho Power's recorded AROs relate to the removal of polychlorinated biphenyls-contaminated equipment at its distribution facilities and the reclamation and removal costs at its jointly owned coal-fired generation facilities. In 2011, changes in estimates at its distribution facilities and at the coal-fired generation facilities resulted in a net increase of $3.9 million in the recorded AROs. The primary cause of the increase in the AROs was the decision to decommission the Boardman generating facility at December 31, 2020. A decommissioning study was performed, and now that a removal date has been determined and the fair value of the associated liabilities can be estimated, ARO amounts related to the Boardman decommissioning are being recognized in the consolidated financial statements.

Idaho Power also has additional AROs associated with its transmission system, hydroelectric facilities, and jointly owned coal-fired generation facilities; however, due to the indeterminate removal date, the fair value of the associated liabilities currently cannot be estimated and no amounts are recognized in the consolidated financial statements.

The regulated operations of Idaho Power also collect removal costs in rates for certain assets that do not have associated AROs. Idaho Power is required to redesignate these removal costs as regulatory liabilities. See Note 3 for the costs recorded as regulatory liabilities on Idaho Power's Balance Sheets as of December 31, 2011 and 2010.

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

	2011	2010
Balance at beginning of year	$ 16,952	$ 16,240
Accretion expense	936	819
Revisions in estimated cash flows	3,930	929
Liability settled	(451)	(1,036)
Balance at end of year	$ 21,367	$ 16,952

13. INVESTMENTS IN DEBT AND EQUITY SECURITIES

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

	2011	2010
Idaho Power investments:		
IERCo	$ 78,530	$ 90,045
Available-for-sale equity securities	22,205	24,561
Executive deferred compensation plan	3,439	4,746
Other investments	2	3
Total Idaho Power investments	$ 104,176	$ 119,805

Investments in Debt and Equity Securities

Investments in available-for-sale securities are reported at fair value, using either specific identification or average cost to determine the cost for computing gains or losses. Any unrealized gains or losses on available-for-sale securities are included in other comprehensive income.

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

	December 31, 2011			December 31, 2010		
	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
Available-for-sale Securities	$ 4,220	$ 1	$ 22,205	$ 4,876	$ -	$ 24,561

At the end of each reporting period, Idaho Power analyzes securities in loss positions to determine whether they have experienced a decline in market value that is considered other-than-temporary. At December 31, 2011, one security was in an immaterial unrealized loss position. No other-than-temporary impairment was recognized for this security due to the limited severity and duration of the unrealized loss position. At December 31, 2010, no securities were in an unrealized loss position. There were no sales of available-for-sale securities during the year ended December 31, 2011 or 2010.

14. DERIVATIVE FINANCIAL INSTRUMENTS

Commodity Price Risk

Idaho Power is exposed to market risk relating to electricity, natural gas, and other fuel commodity prices, all of which are heavily influenced by supply and demand. Market risk may also be influenced by market participants' nonperformance of their contractual obligations and commitments, which affects the supply of or demand for the commodity. Idaho Power uses derivative instruments, such as physical and financial forward contracts, for both electricity and fuel to manage the risks relating to these commodity price exposures. The objective of Idaho Power's energy purchase and sale activity is to meet the demand of retail electric customers, maintain appropriate physical reserves to ensure reliability, and make economic use of temporary surpluses that may develop.

All commodity-related derivative instruments not meeting the normal purchases and normal sales exception to derivative accounting are recorded at fair value on the balance sheet. Because of Idaho Power's PCA mechanisms, unrealized gains and losses associated with the changes in fair value of these derivative instruments are recorded as regulatory assets or liabilities. With the exception of forward contracts for the purchase of natural gas for use at Idaho Power's natural gas generation facilities, Idaho Power's physical forward contracts qualify for the normal purchases and normal sales exception.

All of Idaho Power's derivative instruments have been entered into for the purpose of economically hedging forecasted purchases and sales, though none of these instruments have been designated as cash flow hedges under derivative accounting guidance. Idaho Power offsets fair value amounts recognized on its balance sheet related to derivative instruments executed with the same counterparty under the same master netting agreement.

Derivative Instruments Summary

The tables below presents the fair values and locations of derivative instruments not designated as hedging instruments recorded on the balance sheets at December 31, 2011 and 2010 (in thousands of dollars).

	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	**Fair Value**	**Balance Sheet Location**	**Fair Value**
December 31, 2011				
Current:				
Financial swaps	Other current assets	$ 4,361	Other current assets	$ 1,036
Financial swaps	Other current liabilities	1,526	Other current liabilities	4,755
Forward contracts	Other current assets	70	Other current liabilities	1,370
Long-term:				
Financial swaps	Other assets	359	Other liabilities	108
Total		$ 6,316		$ 7,269
December 31, 2010				
Current:				
Financial swaps	Other current assets	$ 930	Other current assets	$ 356
Financial swaps	Other current liabilities	2,440	Other current liabilities	4,172
Forward contracts			Other current liabilities	508
Long-term:				
Financial swaps	Other liabilities	100	Other liabilities	138
Total		$ 3,470		$ 5,174

The table below presents the gains and losses on derivatives not designated as hedging instruments for the year ended December 31, 2011 and 2010 (in thousands of dollars).

	Location of Gain/(Loss) on Derivatives Recognized in Income	Gain/(Loss) on Derivatives Recognized in Income(1)	
		2011	**2010**
Financial swaps	Off-system sales	$ 9,594	$ 4,499
Financial swaps	Purchased power	(7,124)	(12,240)
Financial swaps	Fuel expense	501	(101)
Financial swaps	Other operations and maintenance	425	-

Forward contracts	Fuel Expense	-	(721)

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

Settlement gains and losses on electricity swap contracts are recorded on the income statement in off-system sales or purchased power depending on the forecasted position being economically hedged by the derivative contract. Settlement gains and losses on both financial and physical contracts for natural gas are reflected in fuel expense. Settlement gains and losses on diesel derivatives are recorded in other operations and maintenance expense. See Note 15 for additional information concerning the determination of fair value for Idaho Power's assets and liabilities from price risk management activities.

Idaho Power had volumes of derivative commodity forward contracts and swaps outstanding at December 31, 2011 and 2010 set forth in the table below.

		December 31,	
Commodity	**Units**	**2011**	**2010**
Electricity purchases	MWh	225,600	347,400
Electricity sales	MWh	1,298,420	338,200
Natural gas purchases	MMBtu	7,928,311	647,900
Natural gas sales	MMBtu	352,129	—
Diesel purchases	Gallons	1,273,997	1,061,969

Credit Risk

At December 31, 2011, Idaho Power did not have material credit exposure from financial instruments, including derivatives. Idaho Power monitors credit risk exposure through reviews of counterparty credit quality, corporate-wide counterparty credit exposure, and corporate-wide counterparty concentration levels. Idaho Power manages these risks by establishing appropriate credit and concentration limits on transactions with counterparties and requiring contractual guarantees, cash deposits, or letters of credit from counterparties or their affiliates, as deemed necessary. Idaho Power's physical power contracts are under Western Systems Power Pool agreements, physical gas contracts are under North American Energy Standards Board contracts, and financial transactions are under International Swaps and Derivatives Association, Inc. contracts. These contracts all contain adequate assurance clauses requiring collateralization if a counterparty has debt that is downgraded below investment grade by at least one rating agency.

Credit-Contingent Features

Certain of Idaho Power's derivative instruments contain provisions that require Idaho Power's unsecured debt to maintain an investment grade credit rating from Moody's Investors Service and Standard & Poor's Ratings Services. If Idaho Power's unsecured debt were to fall below investment grade, it would be in violation of these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a liability position at December 31, 2011, was $7.0 million. Idaho Power posted no collateral related to this amount. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2011, Idaho Power would have been required to post $4.4 million of cash collateral to its counterparties.

15. FAIR VALUE MEASUREMENTS

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

Financial assets and liabilities recorded on the consolidated balance sheet are categorized based on the inputs to the valuation techniques as follows:

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

- Level 2: Financial assets and liabilities whose values are based on:
  a) quoted prices for similar assets or liabilities in active markets;
  b) quoted prices for identical or similar assets or liabilities in non-active markets;
  c) pricing models whose inputs are observable for substantially the full term of the asset or liability; and
  d) pricing models whose inputs are derived principally from or corroborated by observable market data through correlation or other means for substantially the full term of the asset or liability.

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

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

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

The table below presents information about Idaho Power's assets and liabilities measured at fair value on a recurring basis as of December 31, 2011 and 2010 (in thousands of dollars). Idaho Power's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy. There were no transfers between levels for the years presented.

	Quoted Prices in Active Markets for Identical Assets (Level 1)	**Significant Other Observable Inputs (Level 2)**	**Significant Unobservable Inputs (Level 3)**	**Total**
December 31, 2011				
Assets:				
Derivatives	$ 3,654	$ 100	$ —	$ 3,754
Money market funds	100	—	—	100
Trading securities: Equity securities	3,439	—	—	3,439
Available-for-sale securities: Equity securities	22,205	—	—	22,205
Liabilities:				
Derivatives	$ 405	$ 4,302	$ —	$ 4,707

December 31, 2010				
Assets:				
Derivatives	$ 573	$ —	$ —	$ 573
Money market funds	151,173	—	—	151,173
Trading securities: Equity securities	4,746	—	—	4,746
Available-for-sale securities: Equity securities	24,561	—	—	24,561
Liabilities:				
Derivatives	$ —	$ 508	$ —	$ 508

The table below presents the carrying value and estimated fair value of financial instruments that are not reported at fair value, as of December 31, 2011 and 2010, using available market information and appropriate valuation methodologies. The use of different market assumptions and/or estimation methodologies may have a material effect on the estimated fair value amounts. Cash and cash equivalents, deposits, customer and other receivables, notes payable, accounts payable, interest accrued, and taxes accrued are reported at their carrying value as these are a reasonable estimate of their fair value. The estimated fair values for long-term debt are based upon quoted market prices of the same or similar issues or discounted cash flow analysis as appropriate.

	December 31, 2011		**December 31, 2010**	
	Carrying Amount	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
	(thousands of dollars)			
Long-term debt	$ 1,491,727	$ 1,737,912	$ 1,612,790	$ 1,621,425

16. RELATED PARTY TRANSACTIONS

IDACORP: Idaho Power performs corporate functions such as financial, legal, and management services for IDACORP and its subsidiaries. Idaho Power charges IDACORP for the costs of these services based on service agreements and other specifically identified costs. For these services Idaho Power billed IDACORP $0.8 million in 2011and 2010.

Ida-West: Idaho Power purchases all of the power generated by four of Ida-West's hydroelectric projects located in Idaho. Idaho Power paid $9 million and $8 million to Ida-West in 2011 and 2010, respectively.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

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

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

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year	1,820,172			(10,086,835)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				708,772
3	Preceding Quarter/Year to Date Changes in Fair Value	1,149,129			(3,158,753)
4	Total (lines 2 and 3)	1,149,129			(2,449,981)
5	Balance of Account 219 at End of Preceding Quarter/Year	2,969,301			(12,536,816)
6	Balance of Account 219 at Beginning of Current Year	2,969,301			(12,536,816)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				934,902
8	Current Quarter/Year to Date Changes in Fair Value	(400,010)			(2,589,429)
9	Total (lines 7 and 8)	(400,010)			(1,654,527)
10	Balance of Account 219 at End of Current Quarter/Year	2,569,291			(14,191,343)

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1			(8,266,663)		
2			708,772		
3			(2,009,624)		
4			(1,300,852)	140,634,223	139,333,371
5			(9,567,515)		
6			(9,567,515)		
7			934,902		
8			(2,989,439)		
9			(2,054,537)	164,749,627	162,695,090
10			(11,622,052)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

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

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

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	4,467,327,227	4,467,327,227
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	4,467,327,227	4,467,327,227
9	Leased to Others		
10	Held for Future Use	6,974,407	6,974,407
11	Construction Work in Progress	591,474,855	591,474,855
12	Acquisition Adjustments	-454,449	-454,449
13	Total Utility Plant (8 thru 12)	5,065,322,040	5,065,322,040
14	Accum Prov for Depr, Amort, & Depl	1,840,782,085	1,840,782,085
15	Net Utility Plant (13 less 14)	3,224,539,955	3,224,539,955
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	1,818,635,521	1,818,635,521
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	22,587,758	22,587,758
22	Total In Service (18 thru 21)	1,841,223,279	1,841,223,279
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	-441,194	-441,194
33	Total Accum Prov (equals 14) (22,26,30,31,32)	1,840,782,085	1,840,782,085

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

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	5,703	
3	(302) Franchises and Consents	23,165,537	5,855
4	(303) Miscellaneous Intangible Plant	32,983,581	6,847,330
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	56,154,821	6,853,185
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,604,032	111,368
9	(311) Structures and Improvements	139,165,207	5,928,618
10	(312) Boiler Plant Equipment	549,065,614	29,667,912
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	148,799,889	3,873,534
13	(315) Accessory Electric Equipment	59,886,756	613,770
14	(316) Misc. Power Plant Equipment	15,486,549	151,084
15	(317) Asset Retirement Costs for Steam Production	3,515,987	4,489,239
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	917,524,034	44,835,525
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	30,109,969	22,901
28	(331) Structures and Improvements	155,425,385	829,675
29	(332) Reservoirs, Dams, and Waterways	250,750,878	2,241,359
30	(333) Water Wheels, Turbines, and Generators	194,277,265	3,939,061
31	(334) Accessory Electric Equipment	43,762,085	2,219,556
32	(335) Misc. Power PLant Equipment	18,088,684	1,048,665
33	(336) Roads, Railroads, and Bridges	7,521,793	590,698
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	699,936,059	10,891,915
36	D. Other Production Plant		
37	(340) Land and Land Rights	2,599,695	90,311
38	(341) Structures and Improvements	7,169,595	
39	(342) Fuel Holders, Products, and Accessories	4,445,866	
40	(343) Prime Movers	100,801,636	773,156
41	(344) Generators	31,681,900	
42	(345) Accessory Electric Equipment	25,027,598	49,984
43	(346) Misc. Power Plant Equipment	3,118,644	19,793
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	174,844,934	933,244
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	1,792,305,027	56,660,684

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	34,253,938	877,421
49	(352) Structures and Improvements	55,667,437	2,493,112
50	(353) Station Equipment	349,451,391	8,846,585
51	(354) Towers and Fixtures	144,723,540	2,767,876
52	(355) Poles and Fixtures	101,621,493	7,282,014
53	(356) Overhead Conductors and Devices	169,165,595	4,102,430
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices		
56	(359) Roads and Trails	318,351	94,995
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	855,201,745	26,464,433
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	4,745,189	683,210
61	(361) Structures and Improvements	29,485,862	2,881,866
62	(362) Station Equipment	182,593,962	12,192,049
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	225,059,905	5,449,895
65	(365) Overhead Conductors and Devices	120,135,601	3,972,582
66	(366) Underground Conduit	48,215,714	-143,831
67	(367) Underground Conductors and Devices	191,494,213	6,029,113
68	(368) Line Transformers	414,782,133	19,583,109
69	(369) Services	57,319,909	149,486
70	(370) Meters	95,697,525	17,507,437
71	(371) Installations on Customer Premises	2,750,899	84,107
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	4,370,514	58,890
74	(374) Asset Retirement Costs for Distribution Plant	587,980	55,659
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,377,239,406	68,503,572
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	11,123,762	5,004,896
87	(390) Structures and Improvements	77,278,614	7,882,958
88	(391) Office Furniture and Equipment	39,375,541	5,791,888
89	(392) Transportation Equipment	60,957,305	1,751,643
90	(393) Stores Equipment	1,459,340	205,305
91	(394) Tools, Shop and Garage Equipment	5,567,522	682,923
92	(395) Laboratory Equipment	11,946,695	669,571
93	(396) Power Operated Equipment	9,922,182	904,660
94	(397) Communication Equipment	29,214,145	3,918,370
95	(398) Miscellaneous Equipment	4,762,597	759,121
96	SUBTOTAL (Enter Total of lines 86 thru 95)	251,607,703	27,571,335
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant		
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	251,607,703	27,571,335
100	TOTAL (Accounts 101 and 106)	4,332,508,702	186,053,209
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	4,332,508,702	186,053,209

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

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

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

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

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			5,703		2
			23,171,392		3
5,513,809			34,317,102		4
5,513,809			57,494,197		5
					6
					7
8,291			1,707,109		8
1,335,178			143,758,647		9
9,249,301			569,484,225		10
					11
2,022,617			150,650,806		12
374,396			60,126,130		13
457,158			15,180,475		14
			8,005,226		15
13,446,941			948,912,618		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			30,132,870		27
28,047			156,227,013		28
102,137			252,890,100		29
295,465			197,920,861		30
127,274			45,854,367		31
55,915			19,081,434		32
			8,112,491		33
					34
608,838			710,219,136		35
					36
			2,690,006		37
			7,169,595		38
			4,445,866		39
2,623,096			98,951,696		40
			31,681,900		41
			25,077,582		42
			3,138,437		43
					44
2,623,096			173,155,082		45
16,678,875			1,832,286,836		46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
754			35,130,605		48
165,752			57,994,797		49
6,373,227			351,924,749		50
			147,491,416		51
1,876,594			107,026,913		52
1,466,062			171,801,963		53
					54
					55
			413,346		56
					57
9,882,389			871,783,789		58
					59
4,928			5,423,471		60
31,545			32,336,183		61
595,771			194,190,240		62
					63
1,629,356			228,880,444		64
1,571,292			122,536,891		65
82,538			47,989,345		66
822,355			196,700,971		67
4,945,686			429,419,556		68
244,186			57,225,209		69
775,113			112,429,849		70
80,386			2,754,620		71
					72
34,549			4,394,855		73
			643,639		74
10,817,705			1,434,925,273		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			16,128,658		86
176,785			84,984,787		87
4,609,073			40,558,356		88
1,730,819			60,978,129		89
64,609			1,600,036		90
195,449			6,054,996		91
749,944			11,866,322		92
130,356			10,696,486		93
418,171			32,714,344		94
266,700			5,255,018		95
8,341,906			270,837,132		96
					97
					98
8,341,906			270,837,132		99
51,234,684			4,467,327,227		100
					101
					102
					103
51,234,684			4,467,327,227		104

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Boise Operations Center	12/31/82		655,550
3	Production			112,704
4	Transmission Stations			429,822
5	Transmission Lines			68,619
6	Distribution Stations			1,078,590
7	Beacon Light Substation	12/30/02		465,662
8	Homedale Substation	2/29/08		109,453
9	North River Operations Center	1/31/08		2,630,412
10	Line #854 500 Kv	3/31/09		308,066
11				
12				
13				
14	Column B if no date listed it is various			
15				
16				
17				
18				
19				
20				
21	Other Property:			
22	Boise Operations Center	12/31/82		72,785
23	Transmission Stations			199,069
24	Distribution Stations			72,016
25	Homedale Substation	2/29/08		215,719
26	Beacon Light Substation	12/30/02		555,940
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				
43				
44				
45				
46				
47	Total			6,974,407

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	LANGLEY GULCH POWER PLANT CONS	323,852,696
2	ROLLUP RELIC COST BROWNLEE	53,428,991
3	ROLLUP RELIC COST HELLS CANYON	36,542,791
4	BOARDMAN - HEMINGWAY 500 KV LI	26,168,054
5	GATEWAY WEST 500KV LINE	17,858,788
6	ROLLUP RELIC COST OXBOW	16,825,380
7	HELLS CANYON RELICENSING OUTSI	13,681,208
8	CIAC LIABILITY RECLASS	6,478,737
9	LANGLEY GULCH 138/230 KV LINE	6,447,317
10	WQ - ONGOING HELLS CANYON RELI	6,289,342
11	LANGLEY GULCH SWITCHYARD	6,060,641
12	BRIDGER 2008C123LP U1 TURBINE	4,670,643
13	RIVER ENG.-HELLS CANYON CONTIN	4,342,017
14	LANGLEY GULCH PP CONST: WATER	4,129,634
15	LANGLEY GULCH PP CONST: GAS PI	3,368,213
16	CHQ MASTER PLAN - NEW PRIMARY	2,861,799
17	LANGLEY GULCH 230 KV DOUBLE CI	2,807,084
18	MPSN0802 INCREASE CAPACITY OF	2,557,141
19	FISHERIES-HCC RELICENSING REDB	2,536,812
20	ROLLUP RELIC COST SWAN FALLS	2,527,557
21	HCC RELICENSING, FISH2004 INST	2,390,747
22	FISHERIES-HCC RELICENSING ANAD	2,118,048
23	VALMY 98278700 V1BOTTOM ASH PU	1,957,851
24	BOBN REPLACE C233 AND C234 SER	1,803,202
25	B2H TLINE CONSTRUCTION COSTS	1,780,523
26	AERATION FOR UNIT #5 TO IMPROV	1,754,771
27	LEGAL DEPT. LABOR FOR RELICENS	1,527,841
28	BRIDGER UNDISTRIBUTED WORK ORD	1,515,520
29	REL-HCC OREGON REAUTHORIZATION	1,480,417
30	VALMY UNDISTRIBUTED WORK ORDER	1,399,168
31	SWAN FALLS RELICENSING	1,339,913
32	HC LOCAL SERVICE UPGRADE	1,201,965
33	342 COST CENTER DELIVERY CAPIT	1,143,001
34	314 DESIGN TEAMS - CAPITAL - C	1,120,680
35	PAYROLL & IBNR ACCRUAL	1,089,301
36	OTHER MINOR PROJECTS UNDER $1,000,000	24,417,062
37		
38		
39		
40		
41		
42		
43	TOTAL	591,474,855

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

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

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

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	1,750,735,947	1,750,735,947		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	113,001,742	113,001,742		
4	(403.1) Depreciation Expense for Asset Retirement Costs				
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	2,954,462	2,954,462		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9	Fuel Stock	108,272	108,272		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	116,064,476	116,064,476		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	45,706,900	45,706,900		
13	Cost of Removal	6,387,717	6,387,717		
14	Salvage (Credit)	2,607,254	2,607,254		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	49,487,363	49,487,363		
16	Other Debit or Cr. Items (Describe, details in footnote):	1,322,461	1,322,461		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,818,635,521	1,818,635,521		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	527,906,217	527,906,217		
21	Nuclear Production				
22	Hydraulic Production-Conventional	352,777,683	352,777,683		
23	Hydraulic Production-Pumped Storage				
24	Other Production	30,461,718	30,461,718		
25	Transmission	270,518,301	270,518,301		
26	Distribution	528,960,145	528,960,145		
27	Regional Transmission and Market Operation				
28	General	108,011,457	108,011,457		
29	TOTAL (Enter Total of lines 20 thru 28)	1,818,635,521	1,818,635,521		

FOOTNOTE DATA

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

Relocation reimbursements, Up and down costs and damage and insurance claims $ 952,342

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

Accumulated Provision for Depreciation on Asset Retirement Obligation $ 370,120

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

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

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	Idaho Energy Resources Company			
2	Common Stock	02/01/74		500
3	Capital contributions			2,462,594
4	Equity in earnings			70,098,680
5				
6	Subtotal Idaho Energy Resources Company			72,561,774
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 2,463,094		TOTAL	72,561,774

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
5,967,745		76,066,425		4
				5
5,967,745		78,529,519		6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
5,967,745		78,529,519		42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	27,546,983	47,865,097	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)	14,416,312	14,808,824	
8	Transmission Plant (Estimated)	13,365,654	12,917,846	
9	Distribution Plant (Estimated)	13,541,576	13,087,873	
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	897,634	1,201,188	
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	42,221,176	42,015,731	Electric
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)			
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	3,379,745	4,474,719	Electric
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	73,147,904	94,355,547	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	RLE TRANS SIS 74668832	1,480	186623	17,936	186623
3	IPCM TRANS SIS 74705988,74705990,				
4	74705993, 74705995, 74706017	2,669	186623	(1,913)	186623
5	IPCM TRANS SIS 74785240	7,635	186623	2,365	186623
6	IPCM TRANS SIS 74822581-74822582	3,801	186623	5,233	186623
7	IPCM TRANS SIS74875628-74875626	2,631	186623	7,369	186623
8	IPCM TRANS SIS 74875653-74875654-				
9	74875656		186623	10,000	186623
10	IPCM TRANS SIS74905894-74905896		186623	10,000	186623
11	IPCM TRANS SIS 74993330	1,859	186623	(1,859)	186623
12	IPCM TRANS SIS 74978926-74978929	13,558	186623	(13,558)	186623
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	LAVA BEDS WIND PARK	4,452	186623		186623
23	GENERATOR CLUSTER GROUP 1	4,373	186623	95,890	186623
24	HIDDEN HOLLOW EXPANSION GI#291	2,477	186623		186623
25	LITTLE WOOD RIVER GI#292		186623	(1,620)	186623
26	ROCKLAND WIND FARM PROJECT 293	12,491	186623	(9,389)	186623
27	WHEATGRASS RIDGE WIND PROJECT 294	30,811	186623	(93,587)	186623
28	COTTEREL MTN WIND PROJECT 302	14,005	186623		186623
29	ADAMS COUNTY BIOMASS GI#304	65	186623		186623
30	ANTELOPE RIDGE WIND PROJECT 306	1,237	186623	86,209	186623
31	SWAGER FARMS GI#307	2,927	186623	(19,526)	186623
32	DOUBLE B DAIRY GI#308	1,863	186623	(650)	186623
33	ROCK CREEK DAIRY GI#309	1,769	186623	(2,166)	186623
34	GRAND VIEW SOLAR GI#312	1,081	186623		186623
35	YELLOWSTONE PWR GI#315	1,450	186623		186623
36	STANFORD RANCH GI#318	4,661	186623	23,208	186623
37	ROGERSON FLATS GI 322	4,610	186623	(786)	186623
38	JACK RANCH WIND GI 323		186623	5,000	186623
39	JACK RANCH WIND GI 324		186623	10,000	186623
40	SALMON CREEK GI 325	16,644	186623	(30,000)	186623

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	JACK RANCH WIND GI 327	15,832	186623	(20,584)	186623
23	TUMBLE WEED 34.5 GI 332	17,256	186623		186623
24	BENNETT CREEK SOLAR GI 333		186623	231	186623
25	HIGH MESA WIND GI 334	23,839	186623	(68,201)	186623
26	SLATERS FLAT GI 335		186623	530	186623
27	TWO PONDS GI 336	6,621	186623	82,373	186623
28	RYEGRASS WINDFARM GI 337		186623	(1,077)	186623
29	MAINLINE WINDFARM GI 338		186623	(1,078)	186623
30	HAMMETT HILL WINDFARM GI 339		186623	(1,078)	186623
31	DESERT MEADOW WINDFARM GI 340		186623	(1,078)	186623
32	COLD SPRINGS WINDFARM GI 341		186623	(1,078)	186623
33	BEAR CREEK WIND GI 343	2,763	186623	2,496	186623
34	DYNAMIS LANDFILL GI 344	13,346	186623	(21,667)	186623
35	MURPHY FLATS GI 345	7,182	186623	16,310	186623
36	MURPHY FLAT WIND GI 346	9,714	186623	(99,714)	186623
37	AG POWER GI 348	5,533	186623	10,023	186623
38	NOTCH BUTTE GI 349	22,237	186623		186623
39	DEEP CREEK GI 350		186623	663	186623
40	RAINBOW WEST GI 352	28,929	186623	(59,212)	186623

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	RAINBOW RANCH GI 353		186623	573	186623
23	MALAD STATION GI 354	9,716	186623	(9,930)	186623
24	TRADE DOLLAR MINE GI 355		186623	80	186623
25	SALMON FALLS WIND GI 357	2,303	186623	(101,177)	186623
26	MURPHY FLATS GI 358	1,656	186623	(6,457)	186623
27	NOTCHBUTTE GI 359	14,342	186623	(31,000)	186623
28	FARGO DROP GI 360		186623	(88)	186623
29	AG ENERGY GI 361	553	186623	(553)	186623
30	COLEMAN HYDRO GI 362	5,048	186623	(18,975)	186623
31	EIGHTMILE HYDRO GI 366	352	186623	(352)	186623
32	CLARK CANYON HYDRO GI 367	7,151	186623	(7,151)	186623
33	U3 HYDRO GI 368	2,661	186623	(2,661)	186623
34	GRAND VIEW SOLAR TWO GI 369	2,228	186623	(32,147)	186623
35	MEADOW CREEK WIND GI 370	14,350	186623	(153,446)	186623
36	WONDEROUS WIND GI 371	6,565	186623	(6,565)	186623
37	WEST BOISE WASTE WATER GI 372	214	186623	(214)	186623
38	MTNAIR EXPANSION GI 373-378	21,101	186623	(50,000)	186623
39	BANNOCK COUNTY LANDFILL GI 380	2,078	186623	(10,849)	186623
40	DOUBLE EAGLE DAIRY GI 381	939	186623	(939)	186623

Transmission Service and Generation Interconnection Study Costs (continued)

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	FARGO DROP GI 382	9,575	186623	(12,250)	186623
23	BETASEED BIOGAS GI 383	2,913	186623	(1,000)	186623
24	JETTCREEK WINDFARM GI 384		186623	(1,000)	186623
25	PROSPECTOR WINDFARM GI 385		186623	(1,000)	186623
26	BENSON CREEK WINDFARM GI 386		186623	(1,000)	186623
27	DURBIN CREEK WINDFARM GI 387		186623	(1,000)	186623
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) 04/13/2012	Year/Period of Report End of 2011/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets	Balance at Beginning of Current Quarter/Year	Debits	CREDITS Written off During the Quarter/Year Account Charged	CREDITS Written off During the Period Amount	Balance at end of Current Quarter/Year
	(a)	(b)	(c)	(d)	(e)	(f)
1	Asset Retirement Obligations- (182341)	15,371,785	1,022,534	107/230	836,897	15,557,422
2	IPUC Order# 29414-OPUC Order# 04-585					
3						
4	SFAS 133 Mark to Market - ST (182330)	2,239,694	16,405,599	244	14,046,194	4,599,099
5						
6	FAS 133 Mark to Market - LT (182333)	38,140	644,551	244	574,928	107,763
7						
8	FAS 109 Unfunded - Noncurrent (182322)	588,594,650	33,728,127	Various	18,550,599	603,772,178
9						
10	PCA Deferral Idaho - IPUC Order #27660	30,281,079	48,612,766	Various	78,893,845	
11	(Amort period 06/12 thru 05/13) (182323)					
12						
13	PCA Prior Year Deferral Idaho - IPUC Order #27660	(12,721,876)	56,792,870	Various	44,070,994	
14	(Amort period 06/11 thru 05/12) (182324)					
15						
16	Fixed Cost Adjusment Current Year Order #30267	9,474,129	22,833,343	1823	22,034,176	10,273,296
17	(Amort period 06/12 thru 05/13) (182302)					
18						
19	Prior Year FCA IPUC Order #30267 (182309)	2,866,515	61,891,323	1823/400	60,574,666	4,183,172
20						
21	IPUC Grid West loans - IPUC Order #30157	186,434		401	186,434	
22	(Amort period 01/07 - 12/11) (182303)					
23						
24	FERC Grid West Expense - ER08-629-000	195,525		401	83,797	111,728
25	(Amort period 05/08 thru 04/13) (182304)					
26						
27	SFAS 106/158 Post Retirement Benefits	19,031,743	55,020	2283	3,550,586	15,536,177
28	IPUC Order #30256 (182306)					
29						
30	FIN 48 Adjustment Interest Payable	(159,138,028)	160,341,593	282	1,203,565	
31	IPUC Order #30256 (182310)					
32						
33	Pension Deferred FERC Portion (182338)	150,391	1,391,646	1823	1,542,037	
34						
35	Pension Deferred Oregon Order UE-213 (182339)	939,890	439,115	4073	33,518	1,345,487
36						
37	FAS 87 Deferred Pension-IPUC Order #30333 (182321)	8,549,588	27,159,214	Various	18,568,480	17,140,322
38						
39	Unfunded Pension Liability	163,710,092	92,449,107	2283	9,192,434	246,966,765
40	IPUC Order #30256 (182320)					
41						
42	ID DSM Rider Reclass- IPUC Order #29026 (182301)	17,592,938	28,399,653	254	40,670,594	5,321,997
43	PCAM Oregon 2008 OPUC Order #08-238 (182346)	5,956,673	498,312			6,454,985
44	TOTAL	761,425,884	620,622,892		392,854,761	989,194,015

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

OTHER REGULATORY ASSETS (Account 182.3)

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

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1						
2	PCAM Interest Res 2008 OPUC Order #08-238 (182329)	(278,674)	135,798	1823/4210	286,186	-429,062
3						
4	Excess Power Cost Deferral 2007	6,964,691	14,852,011	1823/401	17,054,386	4,762,316
5	IPUC Order #09-189 (182358)					
6						
7	2007 EPC Interest Res IPUC Order #09-189 (182351)	(452,759)	144,480	182/4210	590	-308,869
8						
9	Oregon DSM Rider Reclass-	1,873,675	13,340,738	254	11,676,971	3,537,442
10	OPUC Advice #05-03 (182359)					
11						
12	2009 Reorg IPUC Order #30914	922,622		401	230,655	691,967
13	(Amort period 01/10 thru 12/14) (182318)					
14						
15	OATT Revenue Deferred Reserve IPUC Order #30940	4,675,182	57,346	186	2,668,059	2,064,469
16	(Amort period 01/11 thru 12/13) (182336)					
17						
18	Idaho Pension Cash (182327)	53,169,373	18,681,291	1823/401	32,874,180	38,976,484
19	IPUC Order #31091 Amort Period (06/10 thru 05/11)					
20	IPUC Order #32248 Amort Period (06/11 thru 05/14)					
21						
22	FERC Pension Cash (182328)	1,024,067	981,527	1823/401	1,423,438	582,156
23	IPUC Order #31091 Amort Period (06/10 thru 05/11)					
24	IPUC Order #32248 Amort Period (06/11 thru 05/14)					
25						
26	Excess Power Cost Unbilled Amort (186356)		1,153,467	401	1,296,113	-142,646
27						
28	Cus Efficiency Incentive IPUC Order #32245 (182317)		8,309,903	1823	1,079,179	7,230,724
29						
30	Cus Efficiency Incen Res IPUC Order #32245 (182314)			4210	134,282	-134,282
31						
32	Lidar Surveys IPUC Order #32426		436,047			436,047
33	(Amort period 01/12 thru 12/21) (182361)					
34						
35	Bennett Mtn Maintenance IPUC Order #32426		299,546			299,546
36	(Amort period 01/12 thru 12/15) (182379)					
37						
38	Minor items (18)	208,345	9,565,965	Various	9,516,978	257,332
39						
40						
41						
42						
43						
44	TOTAL	761,425,884	620,622,892		392,854,761	989,194,015

Schedule Page: 232.1 Line No.: 38 Column: a

Accounts included in minor items:
182305
182316
182331
182334
182335
182340
182344
182345
182347
182349
182350
182353
182355
182357
182369
182374
182375
182376

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Rents - Rights of way (186160)	773,585	29,483	Various	87,111	715,957
2						
3	Advance Prepaid (186709)	1,433,219		143	65,958	1,367,261
4	Coal Royalties					
5						
6	Security plan (186720)	21,047,429	1,435,137	143/165	3,480,834	19,001,732
7						
8	American Falls Bond Ref(186722)	206,157		401	14,553	191,604
9	(Amort 04/00 - 7/26)					
10						
11	Prepaid Credit Facility(186025)	60,300	1,981,233	165/431	1,048,863	992,670
12	(Amort 10/11 - 10/15)					
13						
14	Company Owned (186726)	5,624,403	2,196,361	Various	2,762,408	5,058,356
15	Life Insurance					
16						
17	American Falls Water Rights	14,674,956		401	1,042,008	13,632,948
18	(Amort 01/06-12/25) (186727)					
19						
20	Milner Bond Guarantee (186734)	7,445,455		253	1,063,637	6,381,818
21	(Amort 02/07 - 2/17)					
22						
23	American Falls - Bond refinance	679,988		401	47,999	631,989
24	(35 year amortization) (186770)					
25						
26	Shelf Registration-2010(186731)	2,383,894	109,135	181/232	2,460,532	32,497
27						
28	Transmission Deposit	687,741	22,837			710,578
29	PacifiCorp (186784)					
30						
31	Prepaid (186052)	308,302	845,063	Various	502,893	650,472
32	Peoplesoft/Passport					
33	(Various Amortization Periods)					
34						
35	Long Term (186121)	1,306,903		228/401	38,447	1,268,456
36	Workers Compensation					
37						
38	OATT Revenue Deferred Reserve	-2,610,713	2,610,713			
39	Order #30940 (186300)					
40	(amort period 3 years start					
41	date not yet determined)					
42						
43	Long-Term Firm (186624)	919,063	30,299	Various	949,362	
44	Trans Deposits					
45						
46	Power Plant- Valmy J (186793)	98,366	72,991	107/401	34,951	136,406
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	55,131,472				50,880,202

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

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

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1						
2						
3	Power Plant- Boardman (186794)	76,451	88,541	107/401	60,179	104,813
4						
5	Minor Items & Job Orders (5)	15,973	8,637,388	Various	8,650,716	2,645
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	55,131,472				50,880,202

Schedule Page: 233.1 Line No.: 5 Column: a

Accounts included in minor items:
186100
186255
186623
186703
186946

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2			
3	Emission Allowances	-509,154	
4	Advances for Construction	7,061,283	5,117,985
5	Other Electric (See footnote)	6,072,776	46,276,158
6			
7	Other (See footnote)	126,631,210	157,500,863
8	TOTAL Electric (Enter Total of lines 2 thru 7)	139,256,115	208,895,006
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other Non Electric See footnote	18,090,657	19,082,040
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	157,346,772	227,977,046

Notes

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

(Note 1):	Ending Balance	Ending Balance
Revenue Sharing	0.00	10,594,313.78
Post Retiree Benefits-VEBA	5,658,260.39	7,474,519.09
AFUDC Hells Canyon Relicensing	8,292,259.43	12,958,192.16
Rate Case Disallowance	2,765,193.22	2,621,255.57
Stock Based Compensation	2,496,071.09	2,777,080.86
Other Employee's Long Term Deferred Compensation	1,855,361.91	1,344,427.39
Post Retirement Benefits	1,504,637.15	1,172,344.50
Deferred Idaho ITC	4,183,991.50	5,539,826.50
Non-VEBA Pension and Benefits	414,231.42	265,356.10
Oregon-Pension Expense	817,275.90	1,504,842.01
FERC Credit OFA	182,023.59	0.00
IRS Interest Expense	93,084.00	0.00
Pension Expense (Acct 228)	(22,197,833.71)	0.00
Deferred GBC	24,000.00	24,000.00
Bonus Deferral	(514.49)	0.00
Delivery Accruals	(15,265.83)	0.00
Total Other Electric	6,072,775.57	46,276,157.96

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

(Note 2):	Ending Balance	Ending Balance
Pension	64,358,799.67	96,551,656.75
Regulatory Liability for Income Taxes	46,199,137.04	45,472,547.23
Postretirement Plan	8,025,874.06	6,367,217.42
Minimum Pension Liability	8,047,399.21	9,109,441.86
Total Other	126,631,209.98	157,500,863.26

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

(Note 3):	Ending Balance	Ending Balance
Senior Management Security Plan	15,067,824.46	16,319,200.67
SMSP-Market Change of Rabbi Investments	1,626,015.01	1,626,015.01
Micron-CIAC	1,288,362.93	1,050,481.59
Meridian Gold Contributions	108,454.56	86,342.35
Total Non Electric	18,090,656.96	19,082,039.62

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

CAPITAL STOCKS (Account 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Account 201			
2	Common Stock registered on New York	50,000,000	2.50	
3	and Pacific Stock Exchange			
4	Total Common Stock	50,000,000	2.50	
5				
6	Account 204 - None			
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
39,150,812	97,877,030					2
						3
39,150,812	97,877,030					4
						5
						6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

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

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

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

Line No.	Item (a)	Amount (b)
1	Account 208 - Donations received from stockholders - None	
2		
3	Account 209 - Reduction in par or stated value of Capital Stock - None	
4		
5	Account 210 - Gain on reacquired Capital Stock - None	
6		
7		
8	Account 211 - Miscellaneous paid-in Capital - None	
9		
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	TOTAL	

CAPITAL STOCK EXPENSE (Account 214)

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

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1	Common Stock	2,096,925
2		
3		
4		
5		
6		
7		
8		
9		
10	Explanation of Changes during the year:	
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22	TOTAL	2,096,925

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Account 221:		
2	First Mortgage Bonds:		
3	4.50% Series due 2020	130,000,000	1,190,698
4			234,601 D
5			
6	5.50% Series due 2033	70,000,000	728,701
7			36,400 D
8			
9	6.15% Series Due 2019	100,000,000	1,034,909
10			184,949 D
11			
12	3.40% Series due 2020	100,000,000	1,159,871
13			498,864 D
14			
15	5.30% Series Due 2035	60,000,000	408,411 D
16			3,802,019
17			
18	4.25%Series due 2013	70,000,000	641,201
19			372,696 D
20			
21	4.75% Series due 2012	100,000,000	944,356
22			1,047,617 D
23			
24	6.00% Series due 2032	100,000,000	1,191,216
25			543,244 D
26			
27	5.875% Series due 2034	55,000,000	-585,759
28			746,961 D
29			
30	5.50% Series due 2034	50,000,000	524,419
31			383,322 D
32			
33	TOTAL	1,617,045,000	27,130,028

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	4.85% Series Due 2040	100,000,000	1,284,871
2			169,984 D
3			
4	6.30% Series due 2037	140,000,000	1,495,799
5			278,367 D
6			
7	6.25% Series due 2037	100,000,000	1,141,489
8			267,677 D
9			
10	Port of Morrow Variable due 2027	4,360,000	188,545
11			
12	Humboldt Variable due 2024	49,800,000	1,697,856
13			
14	Sweetwater Variable due 2026	116,300,000	3,026,122
15			
16			
17	6.025 % Series Due 2018	120,000,000	1,630,120
18			
19	6.60% Series Due 2011	120,000,000	860,502
20			
21	Subtotal Account 221	1,585,460,000	27,130,028
22			
23	Account 222 - Reaquired Bonds		
24			
25	Account 223: Advances for Associated Companies		
26			
27	Account 224:		
28	Bond Guarantee - American Falls	19,885,000	
29	Note Guarantee - Milner Dam	11,700,000	
30	Subtotal Account 224	31,585,000	
31			
32			
33	TOTAL	1,617,045,000	27,130,028

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
11/20/09	3/1/20	11/20/09	3/1/20	130,000,000	5,850,000	3
						4
						5
05/01/03	04/01/33	05/01/03	03/31/33	70,000,000	3,850,000	6
						7
						8
4/1/09	4/1/19	4/1/09	4/1/19	100,000,000	6,150,000	9
						10
						11
11/1/10	5/1/2020	11/1/10	5/1/20	100,000,000	3,400,000	12
						13
						14
08/26/05	08/26/35	08/26/05	08/26/35	60,000,000	3,180,000	15
						16
						17
05/01/03	10/01/13	05/01/03	09/29/13	70,000,000	2,975,000	18
						19
						20
11/15/02	11/15/12	11/15/02	11/15/12	100,000,000	4,750,000	21
						22
						23
11/15/02	11/15/32	11/15/02	11/15/32	100,000,000	6,000,000	24
						25
						26
08/16/04	08/16/34	08/16/04	08/16/34	55,000,000	3,231,250	27
						28
						29
03/26/04	03/15/34	03/26/04	03/15/34	50,000,000	2,750,000	30
						31
						32
				1,491,726,818	79,348,955	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
2/15/10	8/15/40	2/15/10	8/15/40	100,000,000	4,850,000	1
						2
						3
6/22/07	6/15/2037	6/22/07	6/15/2037	140,000,000	8,820,000	4
						5
						6
10/18/07	10/15/2037	10/18/07	10/15/2037	100,000,000	6,250,000	7
						8
						9
05/17/00	02/01/27	05/17/00	02/01/27	4,360,000	50,255	10
						11
10/22/03	12/01/24	11/01/03	12/01/24	49,800,000	2,564,700	12
						13
10/3/06	7/15/26	10/3/06	7/15/2026	116,300,000	6,105,750	14
						15
						16
7/10/08	7/15/18	7/10/08	7/15/08	120,000,000	7,230,000	17
						18
3/2/01	3/2/11	3/2/01	3/2/11		1,342,000	19
						20
				1,465,460,000	79,348,955	21
						22
						23
						24
						25
						26
						27
04/26/00	2/1/25			19,885,000		28
02/10/92				6,381,818		29
				26,266,818		30
						31
						32
				1,491,726,818	79,348,955	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

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

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

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	164,749,627
2		
3		
4	Taxable Income Not Reported on Books	
5		22,801,060
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		-22,327,229
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		6,698,653
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		130,977,371
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	27,547,434
28	Show Computation of Tax:	
29	Tenative Federal Tax @ 35%	9,641,602
30		
31		
32		
33		
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

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

4003-CONSTRUCTION ADV-252	$	(5,552,281)
4005-AVOIDED COST INT CAP		18,471,438
4006-RETIREMENTS-RECORD TAX GAIN/LOSS		4,000,000
4010-EMISSION ALLOWANCE-254.409-411		1,141,995
4013-CIAC AS TAXABLE INC IN ACCT 107		3,748,724
4018-LINDEN FEEDER DEPOSITS-253.206		0
4021-ENGINEERING FEES-IN ACCT 107-FED ONLY		115,387
4022-FERC CREDIT OFA-254.307		(465,593)
4024-GREEN TAG SALES		2,006,420
4501-ROYALTY INCOME BTL		0
4506-CIAC-MERIDIAN GOLD		(56,560)
4507-CIAC-MICRON-DRAM		(608,470)
Total	**$**	**22,801,060**

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

Total Federal and State taxes deducted on books	$	(44,418,448)
5001-BAD DEBT EXPENSE		(205,868)
5010-SFAS 112-POST-EMPLY BEN 182/253		(849,962)
5014-OVERACCRUED VACATION-ACCT 242		176,500
5017-INJURIES & DAMAGES		42,684
5019-DIRECTORS FEES DEF		26,758
5022-CAPITALIZED OVERHEADS		(17,000,000)
5024-MEALS (50% NON-DEDUCTIBLE) CHRGD TO R.E.		600,000
5025-MILNER FALLING WATER - REV ACCRL		(334,136)
5027-AMORTIZATION OF ACCOUNT 114		(22,723)
5028-OREGON OPER PROPERTY TAX ADJ		(5,072)
5023-PENSION EXPENSE-Acct 228		5,487,134
5033-NONVEBA PEN&BEN-Acct 228		(380,803)
5035-PCA EXPENSE DEFERRAL		30,679,760
5043-AMERICAN FALLS - FALLING WATER CONTRACT-FT		219,181
5047-OTHER EMPLOYEE'S LT DEFERRED COMP-228		(1,306,905)
5052-AMORTIZATION OF ACCOUNT 181		313,103
5053-STOCK BASED COMPENSATION		645,487
5054-IPUC GRID WEST LOANS-ACCT 182		186,435
5055-OPUC GRID WEST LOANS-ACCT 182		14,191
5056-FERC GRID WEST EXP-ACCT 182		83,796
5057-INTERVENER FUNDING ORDERS-ACCT 182		(54,903)
5058-FIXED COST ADJUSTMENT (FCA)-ACCT 182		(2,115,823)
5059-PS & I COSTS-COAL & CHP PLANTS-WRITE OFF		(36,407)
5060-OREGON-PCAM (POWER COST ADJ MECHANISM)		1,220,784
5061-PENSION EXPENSE-OREGON		1,758,706
5062-LIDAR SURVEYS DEFFERAL-ACCT 182		(436,047)
5063-BENNETT MTN MAINT DEFERRAL		(299,546)
5501-SEC PLAN-NET INS COSTS		(76,501)
5503-128-EDC-UNRLZD GN/LS FRM RABBI TRUST		(430,015)
5504-NONDEDUCTIBLE POLITICAL EXP-426.4		875,858
5505-SEC PLAN-BENEFIT ACCR		3,200,861
5510-FINES & PENALTIES-OPERATING		430,042
5531-RATE CASE DISALLOWANCES-REVERSE AMORT		(296,299)
5532-DELIVERY ACCRUALS-253.550		(19,051)

5537-BRIDGER SIERRA RESERVE-LEGAL FEES-Acct 228.4		0
5540-UNREALIZED LOSS ON INVESTMENTS-Acct 124		0
Total	**$**	**(22,327,229)**

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

7010-AFUDC HC RELICENSING-ACCT 229	$	(11,934,857)
7011-OATT REVENUE DEFICIENCY		0
7012-REVENUE SHARING ACCT 25-CURR		(27,098,897)
7501-REVERSE EQUITY EARNINGS OF SUBSIDIARIES		5,967,745
7502-ALLOWANCE FOR OFUDC		25,484,072
7503-ALLOWANCE FOR BFUDC		13,332,724
7504-RECLASS TAX EXEMPT INTEREST-FED ONLY		1,882
7509-SECURITY PLAN-INSURANCE PROCEEDS		945,984
7514-COLI-INSURANCE PROCEEDS		0
7518-IRS INTEREST INCOME		0
Total	**$**	**6,698,653**

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

8001-VEBA-POST RET BNFTS-TRUST-ACCT 228	$	(4,875,119)
8009-DEPR FOR TAX GT OR LT BOOK		82,278,759
8016-VEBA-POST RET BNFTS-TRUST-MEDICARE PART D		803,950
8020-CONSERVATION PROGRAMS		(10,607,175)
8025-MANUFACTURING DEDUCTION		2,698,170
8027-NEVADA OPERATING PROPERTY TAX ADJ		(59,445)
8034-REMOVAL COSTS		6,412,380
8038-OREGON EXCESS PWR SUPPLY COSTS		(2,229,258)
8039-ST TAX-NOT DEDUCTED ON PRIOR RETURN		28,337
8041-AM FALLS - UNAMORTIZED DEBT EXP		(47,999)
8042-GAIN/LOSS ON REACQUIRED DEBT-FT		(911,000)
8057-REORGANIZATION COSTS		(230,656)
8059-SFTWR COSTS-MISC-107-FED ONLY		0
8072-INTANGIBLE ASSET-LABOR DEDUCT-107-FED ONLY		1,369,000
8073-REPAIRS DEDUCTION		40,000,000
8077-PP INS & OTR EXP (1 YR OR LESS)-165		1,659,465
8079-CUSTOM EFFICIENCY INCENTIVE PAY		7,096,442
8501-COLI-TAX ADJ FROM BOOKS		158,095
8504-OREGON NONOP PROPERTY TAX ADJUST		(6)
8703-IPCO - 162 (M) $1m THRESHOLD		0
IRS INTEREST EXPENSE		238,097
STATE INCOME TAX DEDUCTED ON FEDERAL RETURN		7,195,334
Total	**$**	**130,977,371**

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	-21,084,488		7,113,757	-9,913,638	
3	Social Security - (FOAB)	927		12,928,542	12,928,282	
4	Unemployment			120,729	120,729	
5	Subtotal Federal	-21,083,561		20,163,028	3,135,373	
6						
7	State of Idaho:					
8	Property	6,798,477		18,797,490	17,179,867	
9	Non-Operating	11,656		21,567	22,309	
10	Income	1,057,025		7,045,405	8,766,534	
11	KWH	97,149		2,756,722	2,673,193	
12	Unemployment	-1		656,570	656,568	
13	Regulatory Commission			2,089,245	2,089,245	
14	Business License - Sho Ban			150	150	
15	Subtotal Idaho	7,964,306		31,367,149	31,387,866	
16						
17	State of Oregon					
18	Property		1,177,346	2,361,153	2,366,225	
19	Non-Operating Property		838	1,672	1,667	
20	Income	-52,574		55,453	113,672	
21	Regulatory Commission			148,358	148,358	
22	Unemployment			44,926	44,926	
23	Franchise	178,317		703,382	713,729	
24	Subtotal Oregon	125,743	1,178,184	3,314,944	3,388,577	
25						
26	State of Montana:					
27	Property	105,137		271,151	240,805	
28	Subtotal Montana	105,137		271,151	240,805	
29						
30	State of Nevada:					
31	Property		568,203	1,088,598	1,029,152	
32	Subtotal Nevada		568,203	1,088,598	1,029,152	
33						
34	State of Wyoming					
35	Corporate License			4,513	4,513	
36	Property	635,567		1,527,445	1,399,289	
37	Subtotal Wyoming	635,567		1,531,958	1,403,802	
38	Other States Income	9,936		41,969	247	
39	Payroll Adjustment			-13,750,768		
40						
41	TOTAL	-12,242,872	1,746,387	44,028,029	40,585,822	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (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
-4,057,093		8,470,295			-1,356,538	2
1,188		12,928,542				3
		120,729				4
-4,055,905		21,519,566			-1,356,538	5
						6
						7
8,416,100		18,017,423			780,067	8
10,914					21,567	9
-664,104		7,293,032			-247,627	10
180,678		2,756,722				11
1		656,570				12
		2,089,245				13
		150				14
7,943,589		30,813,142			554,007	15
						16
						17
	1,182,418	2,287,728			73,425	18
	834				1,672	19
-110,793		68,371			-12,918	20
		148,358				21
		44,926				22
167,970		703,382				23
57,177	1,183,252	3,252,765			62,179	24
						25
						26
135,483		271,151				27
135,483		271,151				28
						29
						30
	508,757	1,088,598				31
	508,757	1,088,598				32
						33
						34
		4,513				35
763,723		1,527,445				36
763,723		1,531,958				37
51,658		46,837			-4,868	38
		-13,750,768				39
						40
4,895,725	1,692,009	44,773,249			-745,220	41

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

This footnote is for the total of Column I on Page 263. The total of column I and the amounts associated with accounts 408.1 & 409.1 in column I should total back to the sum of lines 14, 15 & 16 on Page 114. For the year 2011 this cross-check will not work as the total of lines 14-16 on Page 114 is $ 74,436,114 additional expense than line 41 on page 263. This difference represents an amount booked for the accounting of FIN 48. When FIN 48 was booked it does use account 409.1, however the other side of the entry is not asociated with FERC account 236 or 165. Therefore FIN 48 will show up in the amount on Page 114 but will not show up on Pages 262 & 263.

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

```
Account 409.2       $   (638,707)
        234.2           (717,831)
                   -------------
Total               $ (1,356,538)
                    =============
```

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

```
Account 107         $  780,067
```

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

```
Account 409.2       $   21,567
```

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

```
Account 409.2       $  (104,386)
        234            (143,241)
                    ------------
Total               $  (247,627)
                    ============
```

Schedule Page: 262 Line No.: 18 Column: l

```
Account 107         $   73,425
```

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

```
Account 409.2       $  1,672
```

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

```
Account 409.2       $  (5,634)
        234            (7,284)
                    ----------
Total               $ (12,918)
                    ==========
```

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

```
Account 409.2       $   (2,440)
        234             (2,428)
                    -----------
Total               $   (4,868)
                    ===========
```

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%	736,844				71,532	
4	7%						
5	10%	25,512,684				1,557,544	
6		1,266,978				26,723	
7	Other - State	44,455,829	411.4	2,222,830	411.4	1,698,965	
8	TOTAL	71,972,335		2,222,830		3,354,764	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Line 6 Col A 11%						
11							
12	State of Idaho	44,455,830	411.4	2,222,830	411.4	1,698,965	
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

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
665,312	10.30		3
			4
23,955,140	16.38		5
1,240,255	47.41		6
44,979,694	26.17		7
70,840,401			8
			9
			10
			11
44,979,695			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
			34
			35
			36
			37
			38
			39
			40
			41
			42
			43
			44
			45
			46
			47
			48

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

OTHER DEFFERED CREDITS (Account 253)

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

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1	Smart Grid (253200)	10,038,255	107/401	170,178,139	172,904,103	12,764,219
2						
3	Point to Point Trans Study(253201)	793,286	232	185,996	268,863	876,153
4						
5	FTV (253202)	4,466,666	400	400,000		4,066,666
6	(Amort Period Mar 1998-Feb 2023)					
7						
8	Sho Ban Trans ROW (253480)	262,500	242	15,000		247,500
9	(Amort Period Jan 2005-Dec 2027)					
10						
11	Milner Falling Water (253953)	1,432,559	186/401	1,063,636	729,498	1,098,421
12	Amort Period (Feb 1992 - Feb 2017)					
13						
14	Postretirement Benefits (253960)	3,848,669	401	849,962		2,998,707
15						
16	Directors Deferred Compensation	4,611,550	131	571,167	597,925	4,638,308
17	(253980-253999)					
18						
19	IBM Mainframe Software Licenses	1,121,312	232	386,459		734,853
20	(Amort period 2010-2015) (253950)					
21						
22	USAF Battery Replacement (253906)	74,384			31,322	105,706
23						
24	Minor Items (2)	19,088	107/401	49,977	30,928	39
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	26,668,269		173,700,336	174,562,639	27,530,572

Schedule Page: 269 Line No.: 24 Column: a

Accounts included in minor items:
253042
253550

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	284,793,872	50,711,765	2,171,003
3	Gas			
4	Other			
5	TOTAL (Enter Total of lines 2 thru 4)	284,793,872	50,711,765	2,171,003
6	Non-Operating Property			
7	Other - Regulatory Asset for I	422,215,476		
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	707,009,348	50,711,765	2,171,003
10	Classification of TOTAL			
11	Federal Income Tax	601,940,143	50,211,165	2,171,003
12	State Income Tax	105,069,205	500,601	
13	Local Income Tax			

NOTES

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

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
						333,334,634	2
							3
							4
						333,334,634	5
							6
		182	-159,138,028	182	18,638,086	599,991,590	7
							8
			-159,138,028		18,638,086	933,326,224	9
							10
			-133,493,583		12,489,768	795,963,656	11
			-25,644,445		6,148,319	137,362,570	12
							13

NOTES (Continued)

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

Account (a)	2011 Beginning Balance b	Changes during Year DR to 410.1 c	CR to 411.1 d	DR 410.2 e	CR 411.2 f	Adj Dr Acct cr g	Amt h	Adj Credits Acct dr i	Amt j	2011 Ending Balance k
Accelerated Depreciation	271,486,739.45	49,981,168.35	0.00							321,467,907.80
Intangible Asset-Labor Deduction	13,260,622.55	556,722.60								13,817,345.15
Valmy Capitalized Items	427,766.00		76,500.00							351,266.00
Engineering Fees in Acct 107	(141,663.20)	8,552.25	40,385.45							(173,496.40)
Misc Software Develop Costs	83,927.20	(66,271.80)								17,655.40
Taxable CIAC in CWIP Bal.	(323,520.40)	231,593.95	2,054,117.45							(2,146,043.90)
TOTAL	284,793,871.60	50,711,765.35	2,171,002.90	0	0		0		0	333,334,634.05

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Other Electric -- See Note	25,656,008	53,826,297	46,760,251
4				
5				
6				
7				
8	Other -- See Note	73,705,667		
9	TOTAL Electric (Total of lines 3 thru 8)	99,361,675	53,826,297	46,760,251
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other -- See Note	265,485		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	99,627,160	53,826,297	46,760,251
20	Classification of TOTAL			
21	Federal Income Tax	83,572,690	45,152,408	39,225,027
22	State Income Tax	16,054,470	8,673,888	7,535,224
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						
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
							2
						32,722,054	3
							4
							5
							6
							7
					30,569,445	104,275,112	8
					30,569,445	136,997,166	9
							10
							11
							12
							13
							14
							15
							16
							17
212,793	36,749					441,529	18
212,793	36,749				30,569,445	137,438,695	19
							20
178,503	30,827				25,643,297	115,291,044	21
34,291	5,922				4,926,147	22,147,650	22
							23

NOTES (Continued)

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

	2011	Changes during Year				Adj Debits		Adj Credits		2011
Account (a)	Beginning Balance b	DR to 410.1 c	CR to 411.1 d	DR to 410.2 e	CR to 411.2 f	Acct cr g	Amt h	Acct dr i	Amt j	Ending Balance k
PCA Expense Deferral	7,056,724.48	5,694,011.99	17,880,218.67							(5,129,482.20)
Conservation Programs	7,610,472.36	5,178,152.68	6,550,673.77							6,237,951.27
Oregon Excess Power Costs	2,556,836.05	828,970.77	1,700,499.18							1,685,307.64
Oregon PCAM	2,219,813.71	123,399.85	600,664.96							1,742,548.60
IPUC Grid West Loans	72,887.11		72,887.11							(0.00)
OATT Revenue Deficiency	807,104.17	0.00	0.00							807,104.17
Reorganization Costs	360,699.07		90,174.97							270,524.10
FERC Grid West Expense	76,440.49		32,760.44							43,680.05
OPUC Grid West Loans	23,116.10	0.00	5,547.97							17,568.13
Intervenor Funding Orders	47,339.76	21,464.33	0.79							68,803.30
Fixed Cost Adjustment	4,824,574.81	4,456,672.84	3,629,491.45							5,651,756.20
PS & I Costs-Coal & CHP Plants-Write Off	(0.02)	14,233.35	0.01							14,233.32
Delivery accruals	0.00	33,341.78	39,163.41							(5,821.63)
Emission Allowance	0.00	142,974.34	47,832.35							95,141.99
Green Tag Sales	0.00	1,644,051.09	784,409.90							859,641.19
LIDAR Surveys Deferral	0.00	170,472.57								170,472.57
Bennett Mtn Maintenance Deferral	0.00	117,107.51								117,107.51
Bonus Deferral	0.00	514.49	12,167.15							(11,652.66)
Pension	0.00	35,400,929.09	15,313,758.58							20,087,170.51
TOTAL	25,656,008.09	53,826,296.68	46,760,250.71	0	0		0		0	32,722,054.06

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

Account (a)	Beginning Balance b	DR to 410.1 c	CR to 411.1 d	DR to 410.2 e	CR to 411.2 f	Acct cr g	Amt h	Acct. dr i	Amt j	Ending Balance k
Pension	64,358,799.67							190	32,192,857.08	96,551,656.75
Postretirement Plan	7,440,460.06							190	(1,366,591.53)	6,073,868.53
Unrealized gains on Mkt Securities	1,906,407.25							219	(256,821.00)	1,649,586.25
TOTAL	73,705,666.98	0	0	0	0		0		30,569,444.55	104,275,111.53

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

	2011	Changes during Year				Adj Debits		Adj Credits		2011
Account (a)	Beginning Balance b	DR to 410.1 c	CR to 411.1 d	DR to 410.2 e	CR to 411.2 f	Acct cr g	Amt h	Acct. dr i	Amt j	Ending Balance k
Advance Coal Royalties	293,553.80			7,931.99	0.00					301,485.79
Oregon Non-Op Prop Tax Adj	327.64			327.61	329.59					325.66
Unrealized Gain/Loss From Rabbit Trust	(28,396.63)			204,533.72	36,419.34					139,717.75
TOTAL	265,484.81	0	0	212,793.32	36,748.93		0		0	441,529.20

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Market to Market Short Term - (254001)	573,226	175	5,235,834	8,057,573	3,394,965
2	IPUC Order #28661					
3						
4	FAS 133 - Market to Market - (254203)		175	1,028,788	1,388,206	359,418
5	IPUC Order # 28661					
6						
7	Emission Sales (254412)	371,211	Various	375,357	9,894	5,748
8	IEEP- Order #30529					
9						
10	Unfunded Accum Def Income Tax (254966)	46,199,138	Various	4,890,414	4,163,823	45,472,547
11						
12	FERC Credit for OFA - IPUC Order #30754	465,593	401	465,593		
13	(Amort period 09/06 - 09/11) (254307)					
14						
15	Oregon Solar Pilot - (254005)	197,625	Various	177,834	746,305	766,096
16	Advice # 10-11					
17						
18	Oregon Reclass (254204)		1823	17,123,830	21,234,150	4,110,320
19	Advice # 05-03					
20						
21	Green Tags Oregon (254415)	195,265	Various	251,458	335,798	279,605
22						
23	Power Cost Adjustment-Current (254423)		1823	36,757,136	47,336,082	10,578,946
24						
25	Regulatory Unfunded Accum Def Income Tax (254419)	7,241,146	1823	8,290,308	4,829,750	3,780,588
26						
27	Revenue Sharing (254101)		Various		27,098,897	27,098,897
28	IPUC Order #30978					
29						
30	BPA Credit Residential Idaho (254401)	13,880	Various	111	397,788	411,557
31	Advice # 11-03					
32						
33	WAQC Carryover (254901)		Various	1,323	160,632	159,309
34	IPUC Order #29505					
35						
36	Minor Items (10)	22,818	Various	118,237,871	118,280,302	65,249
37						
38						
39						
40						
41	TOTAL	55,279,902		192,835,857	234,039,200	96,483,245

Schedule Page: 278 Line No.: 36 Column: a

Accounts included in minor items:
254004
254006
254201
254202
254402
254403
254404
254409
254410
254411
254413
254416

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

ELECTRIC OPERATING REVENUES (Account 400)

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

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	405,981,556	400,606,630
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	322,307,065	338,716,361
5	Large (or Ind.) (See Instr. 4)	140,701,371	138,394,166
6	(444) Public Street and Highway Lighting	3,289,385	3,278,628
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	872,279,377	880,995,785
11	(447) Sales for Resale	101,602,140	78,133,502
12	TOTAL Sales of Electricity	973,881,517	959,129,287
13	(Less) (449.1) Provision for Rate Refunds	37,734,709	10,667,522
14	TOTAL Revenues Net of Prov. for Refunds	936,146,808	948,461,765
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	3,564,200	3,532,831
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	24,256,300	21,141,127
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	38,244,930	44,517,995
22	(456.1) Revenues from Transmission of Electricity of Others	19,372,904	15,398,402
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	85,438,334	84,590,355
27	TOTAL Electric Operating Revenues	1,021,585,142	1,033,052,120

ELECTRIC OPERATING REVENUES (Account 400)

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

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
5,146,013	4,967,379	409,786	407,551	2
				3
5,458,954	5,439,730	82,045	81,571	4
3,099,743	3,075,379	123	124	5
29,720	30,016	1,578	1,459	6
				7
				8
				9
13,734,430	13,512,504	493,532	490,705	10
3,634,924	1,981,936			11
17,369,354	15,494,440	493,532	490,705	12
				13
17,369,354	15,494,440	493,532	490,705	14

Line 12, column (b) includes $ 640,470 of unbilled revenues.

Line 12, column (d) includes 38,351 MWH relating to unbilled revenues

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	440 - Residential Sales:					
2	01 - Residential	5,113,748	402,275,493	409,683	12,482	0.0787
3	03 - Residential Master Meter	4,962	371,277	22	225,545	0.0748
4	04 - Residential - EW	528	41,192	31	17,032	0.0780
5	05 - Residential - TOD	912	71,020	50	18,240	0.0779
6	15 - Dusk to dawn lighting	2,859	537,868			0.1881
7	Unbilled Revenues	22,994	827,035			0.0360
8	Other Revenues		1,862,085			
9	Total 440	5,146,003	405,985,970	409,786	12,558	0.0789
10						
11	442-Commercial & Industrial Sales					
12	07 - General service	162,322	16,053,391	30,972	5,241	0.0989
13	09 - General service	431,095	20,549,318	187	2,305,321	0.0477
14	09 - General service	3,156,665	178,829,445	31,007	101,805	0.0567
15	09 - General service	5,506	294,295	3	1,835,333	0.0534
16	15 - Dusk to Dawn Light	4,103	698,315			0.1702
17	19 - Uniform rate contracts	2,103,035	89,329,869	115	18,287,261	0.0425
18	19 - Uniform rate contracts	6,679	315,835	1	6,679,000	0.0473
19	19 - Uniform rate contracts	119,113	5,280,572	4	29,778,250	0.0443
20	24 - Irrigation Pumping	1,673,408	104,613,138	18,702	89,477	0.0625
21	40 - General service	12,997	877,108	1,174	11,071	0.0675
22	Commercial & Industrial & Unbill	883,784	45,989,630	4	220,946,000	0.0520
23	Other Revenues		173,106			
24	Total 442	8,558,707	463,004,022	82,169	104,160	0.0541
25						
26	444 - Public Street Lighting:					
27	40 - General service	2,824	190,905	839	3,366	0.0676
28	41 - Street lighting	23,946	2,962,492	355	67,454	0.1237
29	42 - Traffic control lighting	2,998	141,953	384	7,807	0.0473
30	Other Revenues	-48	-5,965			0.1243
31	Total 444	29,720	3,289,385	1,578	18,834	0.1107
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	13,696,079	871,638,906	493,533	27,751	0.0636
42	Total Unbilled Rev.(See Instr. 6)	38,351	640,471	0	0	0.0167
43	TOTAL	13,734,430	872,279,377	493,533	27,829	0.0635

Schedule Page: 304 Line No.: 9 Column: b

This amount is different from page 301 column D line 2 in the amount of 10 MWh due to an error during the year where a rate 09S was recorded to the residential account. Page 301 is broken down by FERC account and page 304 is by rate schedule.

Schedule Page: 304 Line No.: 9 Column: c

This amount is different from page 301 column B line 2 in the amount of 4,414 due to an error during the year where a rate 09S was recorded to the residential account. Page 301 is broken down by FERC account and page 304 is by rate schedule.

Schedule Page: 304 Line No.: 24 Column: b

This amount is different from page 301 column D total of lines 4 and 5 in the amount of 10 MWh due to an error during the year where a rate 09S was recorded to the residential account. Page 301 is broken down by FERC account and page 304 is by rate schedule.

Schedule Page: 304 Line No.: 24 Column: c

This amount is different from page 301 column B total of lines 4 and 5 in the amount of 4,414 due to an error during the year where a rate 09S was recorded to the residential account. Page 301 is broken down by FERC account and page 304 is by rate schedule.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Raft River Rural Electric	RQ	V6-44	8.436	8.436	7.176
2	Raft River Rural Electric	RQ	V6-44	n/a	n/a	n/a
3						
4	Arizona Public Service Co.	SF	WSPP	n/a	n/a	n/a
5	Arizona Public Service Co.	OS	WSPP	n/a	n/a	n/a
6	Avista Corp.	SF	WSPP	n/a	n/a	n/a
7	Avista Corp.	OS	WSPP	n/a	n/a	n/a
8	Barclays Bank PLC	SF	WSPP	n/a	n/a	n/a
9	Barclays Bank PLC	OS	-	n/a	n/a	n/a
10	Black Hills Power Inc.	OS	WSPP	n/a	n/a	n/a
11	Black Hills Power Inc.	OS	WSPP	n/a	n/a	n/a
12	Black Hills Power Inc.	SF	WSPP	n/a	n/a	n/a
13	Bonneville Power Administration	SF	WSPP	n/a	n/a	n/a
14	BP Energy Company	SF	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Calpine Energy Services, L.P.	SF	WSPP	n/a	n/a	n/a
2	Cargill Power Markets LLC	OS	-	n/a	n/a	n/a
3	Cargill Power Markets LLC	OS	WSPP	n/a	n/a	n/a
4	Cargill Power Markets LLC	OS	WSPP	n/a	n/a	n/a
5	Cargill Power Markets LLC	SF	WSPP	n/a	n/a	n/a
6	Citigroup Energy Inc.	SF	WSPP	n/a	n/a	n/a
7	Citigroup Energy Inc.	OS	WSPP	n/a	n/a	n/a
8	Citigroup Energy Inc.	OS	-	n/a	n/a	n/a
9	Clatskanie PUD	SF	WSPP	n/a	n/a	n/a
10	Constellation Energy Commodities Group,	SF	WSPP	n/a	n/a	n/a
11	DB Energy Trading LLC	SF	WSPP	n/a	n/a	n/a
12	EDF Trading North America, LLC	SF	WSPP	n/a	n/a	n/a
13	Eugene Electric Board	SF	WSPP	n/a	n/a	n/a
14	Exelon Generation Company, LLC	SF	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Grant CO Public Utility District #2 --	SF	WSPP	n/a	n/a	n/a
2	IBERDROLA RENEWABLES, Inc.	OS	WSPP	n/a	n/a	n/a
3	IBERDROLA RENEWABLES, Inc.	SF	WSPP	n/a	n/a	n/a
4	IBERDROLA RENEWABLES, Inc.	OS	WSPP	n/a	n/a	n/a
5	IBERDROLA RENEWABLES, Inc.	OS	-	n/a	n/a	n/a
6	J.P. Morgan Ventures Energy Corporation	OS	-	n/a	n/a	n/a
7	J.P. Morgan Ventures Energy Corporation	SF	WSPP	n/a	n/a	n/a
8	Jeffries Bache	OS	-	n/a	n/a	n/a
9	Macquarie Energy LLC	OS	WSPP	n/a	n/a	n/a
10	Macquarie Energy LLC	SF	WSPP	n/a	n/a	n/a
11	Morgan Stanley Capital Group Inc.	OS	-	n/a	n/a	n/a
12	Morgan Stanley Capital Group Inc.	OS	-	n/a	n/a	n/a
13	Morgan Stanley Capital Group Inc.	SF	V6-62	n/a	n/a	n/a
14	Morgan Stanley Capital Group Inc.	OS	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical 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	NorthWestern Energy	OS	WSPP	n/a	n/a	n/a
2	PacifiCorp Inc.	S	WSPP	n/a	n/a	n/a
3	PacifiCorp Inc.	OS	WSPP	n/a	n/a	n/a
4	PacifiCorp Inc.	SF	T-7	n/a	n/a	n/a
5	Portland General Electric Company	OS	WSPP	n/a	n/a	n/a
6	Portland General Electric Company	OS	WSPP	n/a	n/a	n/a
7	Portland General Electric Company	SF	WSPP	n/a	n/a	n/a
8	Powerex Corp.	OS	WSPP	n/a	n/a	n/a
9	Powerex Corp.	OS	WSPP	n/a	n/a	n/a
10	Powerex Corp.	SF	WSPP	n/a	n/a	n/a
11	PPL EnergyPlus, LLC	OS	WSPP	n/a	n/a	n/a
12	PPL EnergyPlus, LLC	OS	WSPP	n/a	n/a	n/a
13	PPL EnergyPlus, LLC	SF	WSPP	n/a	n/a	n/a
14	Puget Sound Energy, Inc.	SF	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Puget Sound Energy, Inc.	SF	T-7	n/a	n/a	n/a
2	Puget Sound Energy, Inc.	OS	WSPP	n/a	n/a	n/a
3	Rainbow Energy Marketing Corporation	OS	WSPP	n/a	n/a	n/a
4	Rainbow Energy Marketing Corporation	SF	WSPP	n/a	n/a	n/a
5	Royal Bank of Canada	OS	-	n/a	n/a	n/a
6	Seattle City Light	OS	WSPP	n/a	n/a	n/a
7	Seattle City Light	SF	WSPP	n/a	n/a	n/a
8	Sempra Energy Trading LLC	OS	-	n/a	n/a	n/a
9	Sempra Energy Trading LLC	OS	WSPP	n/a	n/a	n/a
10	Shell Energy North America (US), L.P.	OS	WSPP	n/a	n/a	n/a
11	Shell Energy North America (US), L.P.	OS	WSPP	n/a	n/a	n/a
12	Shell Energy North America (US), L.P.	OS	WSPP	n/a	n/a	n/a
13	Shell Energy North America (US), L.P.	OS	WSPP	n/a	n/a	n/a
14	Shell Energy North America (US), L.P.	SF	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical 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	Sierra Pacific Power Co., dba NV Energy	SF	T-7	n/a	n/a	n/a
2	Sierra Pacific Power Co., dba NV Energy	OS	WSPP	n/a	n/a	n/a
3	Sierra Pacific Power Co., dba NV Energy	SF	WSPP	n/a	n/a	n/a
4	Sierra Pacific Power Co., dba NV Energy	OS	WSPP	n/a	n/a	n/a
5	Southern California Edison	OS	WSPP	n/a	n/a	n/a
6	Snohomish County PUD	SF	WSPP	n/a	n/a	n/a
7	Tenaska Power Services Co.	OS	WSPP	n/a	n/a	n/a
8	Tenaska Power Services Co.	SF	WSPP	n/a	n/a	n/a
9	Tenaska Power Services Co.	OS	WSPP	n/a	n/a	n/a
10	The Energy Authority, Inc.	SF	WSPP	n/a	n/a	n/a
11	TransAlta Energy Marketing (U.S.) Inc.	OS	WSPP	n/a	n/a	n/a
12	TransAlta Energy Marketing (U.S.) Inc.	OS	WSPP	n/a	n/a	n/a
13	TransAlta Energy Marketing (U.S.) Inc.	SF	WSPP	n/a	n/a	n/a
14	Turlock Irrigation District	SF	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical 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	United Materials of Great Falls	LF	61	n/a	n/a	n/a
2	Wells Fargo Bank, N.A.	OS	-	n/a	n/a	n/a
3	Marcquarie Energy LLC	AD	WSPP	n/a	n/a	n/a
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**

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
38,222	540,239	1,085,425	4,500	1,630,164	1
			254,060	254,060	2
					3
533,806		13,314,698		13,314,698	4
3,600		93,600		93,600	5
4,050		84,748		84,748	6
290		3,140		3,140	7
30,000		1,502,700		1,502,700	8
		94,553		94,553	9
			2,295	2,295	10
34,301		702,444		702,444	11
44,873		779,325		779,325	12
55,635		1,528,500		1,528,500	13
63,160		717,310		717,310	14
38,222	540,239	1,085,425	258,560	1,884,224	
3,596,702	0	98,041,629	1,676,287	99,717,916	
3,634,924	**540,239**	**99,127,054**	**1,934,847**	**101,602,140**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
10		378		378	1
		14,492		14,492	2
			695,944	695,944	3
951		23,623		23,623	4
386,461		11,442,864		11,442,864	5
560,092		13,799,257		13,799,257	6
6,244		167,095		167,095	7
		341,599		341,599	8
16,800		463,000		463,000	9
44,800		1,155,785		1,155,785	10
42,750		1,091,669		1,091,669	11
85,400		2,461,720		2,461,720	12
13,710		248,556		248,556	13
800		26,400		26,400	14
38,222	540,239	1,085,425	258,560	1,884,224	
3,596,702	0	98,041,629	1,676,287	99,717,916	
3,634,924	**540,239**	**99,127,054**	**1,934,847**	**101,602,140**	

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.
5,600		151,320		151,320	1
			9,407	9,407	2
127,040		3,325,760		3,325,760	3
341		7,408		7,408	4
		68,748		68,748	5
		765,968		765,968	6
10,422		325,674		325,674	7
		6,807,639		6,807,639	8
		524,508		524,508	9
169,183		5,696,223		5,696,223	10
		138,330		138,330	11
		10,732		10,732	12
225,125		4,786,783		4,786,783	13
			111,981	111,981	14
38,222	540,239	1,085,425	258,560	1,884,224	
3,596,702	0	98,041,629	1,676,287	99,717,916	
3,634,924	**540,239**	**99,127,054**	**1,934,847**	**101,602,140**	

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.
4,258		27,573		27,573	1
68,075		894,457		894,457	2
			158	158	3
190		4,970		4,970	4
			584	584	5
2,925		34,350		34,350	6
16,671		412,810		412,810	7
			490,861	490,861	8
196,235		2,540,384		2,540,384	9
34,508		856,711		856,711	10
			14,900	14,900	11
335		2,459		2,459	12
56,880		1,609,656		1,609,656	13
57,402		1,451,355		1,451,355	14
38,222	540,239	1,085,425	258,560	1,884,224	
3,596,702	0	98,041,629	1,676,287	99,717,916	
3,634,924	**540,239**	**99,127,054**	**1,934,847**	**101,602,140**	

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
3		88		88	1
15,915		228,295		228,295	2
			126,369	126,369	3
132,200		3,796,180		3,796,180	4
		142,696		142,696	5
1,100		13,675		13,675	6
4,140		109,050		109,050	7
		672,024		672,024	8
			29	29	9
		37,302		37,302	10
			15,451	15,451	11
3,584		99,168		99,168	12
41,696		864,566		864,566	13
286,405		7,531,637		7,531,637	14
38,222	540,239	1,085,425	258,560	1,884,224	
3,596,702	0	98,041,629	1,676,287	99,717,916	
3,634,924	**540,239**	**99,127,054**	**1,934,847**	**101,602,140**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE: Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
69		2,066		2,066	1
			194,888	194,888	2
200		6,000		6,000	3
2		52		52	4
			109	109	5
50		1,100		1,100	6
			2,547	2,547	7
100		2,500		2,500	8
14,393		115,296		115,296	9
250		6,200		6,200	10
			10,764	10,764	11
141,558		2,419,207		2,419,207	12
51,664		1,377,652		1,377,652	13
400		10,028		10,028	14
38,222	540,239	1,085,425	258,560	1,884,224	
3,596,702	0	98,041,629	1,676,287	99,717,916	
3,634,924	**540,239**	**99,127,054**	**1,934,847**	**101,602,140**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
		26,446		26,446	1
		77,127		77,127	2
50		2,000		2,000	3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
38,222	540,239	1,085,425	258,560	1,884,224	
3,596,702	0	98,041,629	1,676,287	99,717,916	
3,634,924	**540,239**	**99,127,054**	**1,934,847**	**101,602,140**	

Name of Respondent Idaho Power Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report 2011/Q4

FOOTNOTE DATA

Schedule Page: 310 Line No.: 1 Column: b
Customer Charge
Schedule Page: 310 Line No.: 2 Column: b
Network Transmission Charges
Schedule Page: 310 Line No.: 5 Column: b
Non-firm Sales
Schedule Page: 310 Line No.: 7 Column: b
Non-firm Sales
Schedule Page: 310 Line No.: 9 Column: b
ISDA Master Agreement with Barclays Bank dated May 2, 2011
Schedule Page: 310 Line No.: 10 Column: b
Financial Transmission Losses
Schedule Page: 310 Line No.: 11 Column: b
Non-firm Sales
Schedule Page: 310.1 Line No.: 2 Column: b
ISDA Master Agreement with Cargil Powr Markets LLC, dated June 13, 2011
Schedule Page: 310.1 Line No.: 3 Column: b
Financial Transmission Losses
Schedule Page: 310.1 Line No.: 4 Column: b
Non-firm Sales
Schedule Page: 310.1 Line No.: 7 Column: b
Unit Contingent
Schedule Page: 310.1 Line No.: 8 Column: b
ISDA Master Agreement with Citigroup Energy, Inc., dated March 7, 2011
Schedule Page: 310.2 Line No.: 2 Column: b
Financial Transmission Losses
Schedule Page: 310.2 Line No.: 4 Column: b
Non-firm Sales
Schedule Page: 310.2 Line No.: 5 Column: b
ISDA Master Agreement with Iberdrola Renewables, Inc., dated July 19, 2011
Schedule Page: 310.2 Line No.: 6 Column: b
ISDA Master Agreement with JP Morgan Ventures Energy Corporation dated November 4, 2005.
Schedule Page: 310.2 Line No.: 8 Column: b
Prudential Bache Commodities (Jeffries Bache), LLC Futures Account Document, dated September 4, 2008.
Schedule Page: 310.2 Line No.: 9 Column: b
ISDA Master Agreement with Macquarie Energy, LLC dated April 12, 2011
Schedule Page: 310.2 Line No.: 11 Column: b
ISDA Master Agreement with Morgan Stanley dated March 1, 2000
Schedule Page: 310.2 Line No.: 12 Column: b
ISDA Master Agreement with Morgan Stanley dated March 1, 2000
Schedule Page: 310.2 Line No.: 14 Column: b
Financial Transmission Losses
Schedule Page: 310.3 Line No.: 1 Column: b
Non-firm Sales
Schedule Page: 310.3 Line No.: 3 Column: b
Financial Transmission Losses
Schedule Page: 310.3 Line No.: 4 Column: b
Spinning or Operating Reserves
Schedule Page: 310.3 Line No.: 5 Column: b
Financial Transmission Losses
Schedule Page: 310.3 Line No.: 6 Column: b
Non-firm Sales

Schedule Page: 310.3 Line No.: 8 Column: b
Financial Transmission Losses
Schedule Page: 310.3 Line No.: 9 Column: b
Non-firm Sales
Schedule Page: 310.3 Line No.: 11 Column: b
Financial Transmission Losses
Schedule Page: 310.3 Line No.: 12 Column: b
Non-firm Sales
Schedule Page: 310.4 Line No.: 1 Column: b
Spinning or Operating Reserves
Schedule Page: 310.4 Line No.: 2 Column: b
Non-firm Sales
Schedule Page: 310.4 Line No.: 3 Column: b
Financial Transmission Losses
Schedule Page: 310.4 Line No.: 5 Column: b
ISDA Master Agreement with Royal Bank of Canada dated August 26, 2005
Schedule Page: 310.4 Line No.: 6 Column: b
Non-firm Sales
Schedule Page: 310.4 Line No.: 8 Column: b
ISDA Master Agreement with Sempra Energy Trading dated February 21, 2008.
Schedule Page: 310.4 Line No.: 9 Column: b
Financial Transmission Losses
Schedule Page: 310.4 Line No.: 10 Column: b
ISDA Master Agreement with Shell Energy North America dated November 1, 2009
Schedule Page: 310.4 Line No.: 11 Column: b
Financial Transmission Losses
Schedule Page: 310.4 Line No.: 12 Column: b
Unit Contingent
Schedule Page: 310.4 Line No.: 13 Column: b
Non-firm Sales
Schedule Page: 310.5 Line No.: 1 Column: b
Spinning or Operating Reserves
Schedule Page: 310.5 Line No.: 2 Column: b
Financial Transmission Losses
Schedule Page: 310.5 Line No.: 4 Column: b
Non-firm Sales
Schedule Page: 310.5 Line No.: 5 Column: b
Financial Transmission Losses
Schedule Page: 310.5 Line No.: 7 Column: b
Financial Transmission Losses
Schedule Page: 310.5 Line No.: 9 Column: b
Non-firm Sales
Schedule Page: 310.5 Line No.: 11 Column: b
Financial Transmission Losses
Schedule Page: 310.5 Line No.: 12 Column: b
Non-firm Sales
Schedule Page: 310.6 Line No.: 2 Column: b
ISDA Master Agreement with Wells Fargo Bank, N.A. dated March 1, 2006
Schedule Page: 310.6 Line No.: 3 Column: b
December 2010 Adjustment

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	1,690,161	1,888,571
5	(501) Fuel	119,844,954	146,926,801
6	(502) Steam Expenses	6,950,410	7,337,561
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	2,231,309	2,140,193
10	(506) Miscellaneous Steam Power Expenses	9,734,263	9,797,755
11	(507) Rents	498,085	229,315
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	140,949,182	168,320,196
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	2,075,559	2,292,767
16	(511) Maintenance of Structures	920,609	309,374
17	(512) Maintenance of Boiler Plant	15,351,039	16,067,832
18	(513) Maintenance of Electric Plant	6,827,635	3,915,291
19	(514) Maintenance of Miscellaneous Steam Plant	6,486,063	3,753,015
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	31,660,905	26,338,279
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	172,610,087	194,658,475
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	5,380,371	5,362,099
45	(536) Water for Power	8,772,110	7,322,751
46	(537) Hydraulic Expenses	12,513,192	10,671,807
47	(538) Electric Expenses	1,611,582	1,565,842
48	(539) Miscellaneous Hydraulic Power Generation Expenses	3,081,121	2,895,723
49	(540) Rents	209,213	406,432
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	31,567,589	28,224,654
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	1,763,673	1,967,876
54	(542) Maintenance of Structures	1,722,862	1,155,653
55	(543) Maintenance of Reservoirs, Dams, and Waterways	1,563,284	1,368,190
56	(544) Maintenance of Electric Plant	1,789,947	3,177,811
57	(545) Maintenance of Miscellaneous Hydraulic Plant	2,719,281	3,029,473
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	9,559,047	10,699,003
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	41,126,636	38,923,657

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	820,192	328,417
63	(547) Fuel	11,696,917	12,745,952
64	(548) Generation Expenses	749,804	448,744
65	(549) Miscellaneous Other Power Generation Expenses	779,335	450,180
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	14,046,248	13,973,293
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		43
70	(552) Maintenance of Structures	179,520	182,043
71	(553) Maintenance of Generating and Electric Plant	115,128	118,533
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	1,861,365	1,077,264
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	2,156,013	1,377,883
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	16,202,261	15,351,176
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	156,873,749	137,850,336
77	(556) System Control and Load Dispatching	1,219	160
78	(557) Other Expenses	41,459,600	53,795,016
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	198,334,568	191,645,512
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	428,273,552	440,578,820
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	3,326,891	2,992,955
84	(561) Load Dispatching	192,086	273,869
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,188,357	1,254,735
87	(561.3) Load Dispatch-Transmission Service and Scheduling	1,423,636	1,316,482
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development		
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies	102,697	108,008
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	2,252,352	1,987,214
94	(563) Overhead Lines Expenses	746,070	660,035
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	6,462,104	5,918,507
97	(566) Miscellaneous Transmission Expenses	307,899	336,835
98	(567) Rents	3,283,621	1,569,168
99	TOTAL Operation (Enter Total of lines 83 thru 98)	19,285,713	16,417,808
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	220,612	540,340
102	(569) Maintenance of Structures		195
103	(569.1) Maintenance of Computer Hardware	54,018	66,482
104	(569.2) Maintenance of Computer Software	347,776	324,033
105	(569.3) Maintenance of Communication Equipment	26,183	28,510
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	2,975,539	3,447,662
108	(571) Maintenance of Overhead Lines	3,675,361	2,781,256
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	5,474	-40
111	TOTAL Maintenance (Total of lines 101 thru 110)	7,304,963	7,188,438
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	26,590,676	23,606,246

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	3,746,431	3,713,391
135	(581) Load Dispatching	3,482,055	3,419,960
136	(582) Station Expenses	1,192,869	1,277,818
137	(583) Overhead Line Expenses	3,039,224	3,029,340
138	(584) Underground Line Expenses	1,825,857	1,792,342
139	(585) Street Lighting and Signal System Expenses	122,065	79,537
140	(586) Meter Expenses	4,130,937	4,219,270
141	(587) Customer Installations Expenses	1,092,077	1,521,427
142	(588) Miscellaneous Expenses	5,494,553	5,004,179
143	(589) Rents	830,940	440,788
144	TOTAL Operation (Enter Total of lines 134 thru 143)	24,957,008	24,498,052
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	402,381	371,979
147	(591) Maintenance of Structures	5,711	-11,385
148	(592) Maintenance of Station Equipment	3,230,860	3,774,723
149	(593) Maintenance of Overhead Lines	14,495,482	14,297,636
150	(594) Maintenance of Underground Lines	1,054,033	1,003,405
151	(595) Maintenance of Line Transformers	433,841	448,157
152	(596) Maintenance of Street Lighting and Signal Systems	554,042	587,953
153	(597) Maintenance of Meters	472,599	700,080
154	(598) Maintenance of Miscellaneous Distribution Plant	252,535	137,583
155	TOTAL Maintenance (Total of lines 146 thru 154)	20,901,484	21,310,131
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	45,858,492	45,808,183
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	427,283	410,702
160	(902) Meter Reading Expenses	2,453,647	4,026,937
161	(903) Customer Records and Collection Expenses	12,944,062	12,988,731
162	(904) Uncollectible Accounts	4,269,718	4,638,855
163	(905) Miscellaneous Customer Accounts Expenses	252	342
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	20,094,962	22,065,567

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	528,250	352,779
168	(908) Customer Assistance Expenses	44,034,548	51,959,849
169	(909) Informational and Instructional Expenses	82,775	31,517
170	(910) Miscellaneous Customer Service and Informational Expenses	531,823	864,003
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	45,177,396	53,208,148
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses		
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)		
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	67,143,039	63,660,597
182	(921) Office Supplies and Expenses	15,742,902	13,613,991
183	(Less) (922) Administrative Expenses Transferred-Credit	26,009,805	27,799,634
184	(923) Outside Services Employed	4,925,844	7,210,630
185	(924) Property Insurance	3,207,120	3,329,577
186	(925) Injuries and Damages	5,806,100	5,668,380
187	(926) Employee Pensions and Benefits	60,010,908	30,031,098
188	(927) Franchise Requirements		2,549
189	(928) Regulatory Commission Expenses	3,449,337	3,797,836
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	552,129	417,950
192	(930.2) Miscellaneous General Expenses	3,750,121	3,826,102
193	(931) Rents	7,103	12,600
194	TOTAL Operation (Enter Total of lines 181 thru 193)	138,584,798	103,771,676
195	Maintenance		
196	(935) Maintenance of General Plant	4,522,111	4,182,610
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	143,106,909	107,954,286
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	709,101,987	693,221,250

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	Cogeneration and Small Power Producers					
2	AgPower Jerome/Double A Digester	LU	-	N/A	N/A	N/A
3	Allan Ravenscroft/Malad River	LU	-	.488		
4	Bennett Creek Wind Farm	LU	-	N/A	N/A	N/A
5	Bettencourt DryCreek Biofactory	LU	-	N/A	N/A	N/A
6	Big Sky West Dairy Digester	LU	-	N/A	N/A	N/A
7	Big Wood Canal Company					
8	Black Canyon #3	LU	-	N/A	N/A	N/A
9	Jim Knight	LU	-	N/A	N/A	N/A
10	Sagebrush	LU	-	N/A	N/A	N/A
11	Blind Canyon Hydro	LU	-	N/A	N/A	N/A
12	Branchflower/Trout Company	LU	-	N/A	N/A	N/A
13	Burley Butte Wind Park	LU	-	N/A	N/A	N/A
14	Bypass Limited	LU	-	N/A	N/A	N/A
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Camp Reed Wind Park	LU	-	N/A	N/A	N/A
2	Cargill Inc./B6 Anaerobic Digester	LU	-	N/A	N/A	N/A
3	Cassia Gulch Wind Park	LU	-	N/A	N/A	N/A
4	Cassia Wind Farm	LU	-	N/A	N/A	N/A
5	City of Cove, Oregon/Mill Creek	LU	-	N/A	N/A	N/A
6	City of Hailey	LU	-	N/A	N/A	N/A
7	City of Pocatello	LU	-	N/A	N/A	N/A
8	Clear Springs Food Inc.	LU	-	N/A	N/A	N/A
9	Clifton E. Jenson/Birchcreek	LU	-	.05		
10	Consolidated Hydro Inc./Enel					
11	Barber Dam	LU	-	N/A	N/A	N/A
12	GeoBon #2	LU	-	N/A	N/A	N/A
13	Rock Creek #2	LU	-	N/A	N/A	N/A
14	Dietrich Drop	LU	-	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Lowline #2	LU	-	N/A	N/A	N/A
2	Contractors Power Group Inc./Mile 28	LU	-	N/A	N/A	N/A
3	Crystal Springs Hydro	LU	-	N/A	N/A	N/A
4	Curry Cattle Company	LU	-	.084		
5	David McCollum/Canyon Springs	LU	-	N/A	N/A	N/A
6	David R Snedigar	LU	-	N/A	N/A	N/A
7	D.R. Johnson Lumber/Co Gen Co	SF	-	N/A	N/A	N/A
8	Faulkner Brothers Hydro Inc.	LU	-	N/A	N/A	N/A
9	Fisheries Development	OS	-	N/A	N/A	N/A
10	Fossil Gulch Wind	LU	-	N/A	N/A	N/A
11	G2 Energy Hidden Hollow	LU	-	N/A	N/A	N/A
12	Glenns Ferry Cogen Partners/Magic	LU	-	N/A	N/A	N/A
13	Golden Valley Wind Park	LU	-	N/A	N/A	N/A
14	Hazelton B Power Company	LU	-	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	H.K. Hydro Mud Creek S & S	LU	-	N/A	N/A	N/A
2	Horeshoe Bend Hydro	LU	-	N/A	N/A	N/A
3	Horseshoe Bend Wind/United Materials	LU	-	N/A	N/A	N/A
4	Hot Springs Wind Farm	LU	-	N/A	N/A	N/A
5	Idaho Winds/Sawtooth Wind Project	LU	-	N/A	N/A	N/A
6	JR Simplot Co.	LU	-	N/A	N/A	N/A
7	J.M. Miller/Sahko Hydro	LU	-	N/A	N/A	N/A
8	James B. Howell/CHI Elk Creek	LU	-	N/A	N/A	N/A
9	John R LeMoyne	LU	-	N/A	N/A	N/A
10	Kasel & Witherspoon	LU	-	N/A	N/A	N/A
11	Koyle Hydro Inc.	LU	-	N/A	N/A	N/A
12	Lateral 10 Ventures	LU	-	N/A	N/A	N/A
13	Lemhi Hydro Power Co./Schaffner	LU	-	N/A	N/A	N/A
14	Lime Wind	LU	-	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Little Mac Power Co./Cedar Draw	LU	-	N/A	N/A	N/A
2	Little Wood River Irrigation District	LU	-	N/A	N/A	N/A
3	Magic Reservoir Hydro	LU	-	N/A	N/A	N/A
4	Marco Rancher's Irrigation Inc.	LU	-	N/A	N/A	N/A
5	Marysville Hydro Partners/Falls River	LU	-	N/A	N/A	N/A
6	Milner Dam Wind Park	LU	-	N/A	N/A	N/A
7	Mud Creek White Hydro, Inc	LU	-	N/A	N/A	N/A
8	Oregon Trail Wind Park	LU	-	N/A	N/A	N/A
9	Owyhee Irrigation District					
10	Mitchell Butte	LU	-	N/A	N/A	N/A
11	Owyhee Dam	LU	-	N/A	N/A	N/A
12	Tunnel #1	LU	-	N/A	N/A	N/A
13	Paynes Ferry Wind Park	LU	-	N/A	N/A	N/A
14	Pigeon Cove Power	LU	-	1.389		
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Pilgrim Stage Station Wind Park	LU	-	N/A	N/A	N/A
2	Pristine Springs Inc #3	LU	-	N/A	N/A	N/A
3	Pristine Springs Inc #1	LU	-	N/A	N/A	N/A
4	Reynolds Irrigation District	LU	-	N/A	N/A	N/A
5	Richard Kaster					
6	Box Canyon	LU	-	N/A	N/A	N/A
7	Briggs Creek	LU	-	N/A	N/A	N/A
8	Rim View Trout Company	OS	-	N/A	N/A	N/A
9	Riverside Hydro/Mora Drop	LU	-	N/A	N/A	N/A
10	Riverside Investments/Arena Drop	LU	-	N/A	N/A	N/A
11	Rock Creek #1 Joint Venture	LU	-	1.732		
12	Rockland Wind Project	LU	-	N/A	N/A	N/A
13	Rupert Cogen Partners/Magic Valley	LU	-	N/A	N/A	N/A
14	Salmon Falls Wind Park	LU	-	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)	Average Monthly CP Demand (f)
1	SE Hazelton A LP	LU	-	N/A	N/A	N/A
2	Shorock Hydro Inc.					
3	Shoshone Cspp	LU	-	N/A	N/A	N/A
4	Shoshone #2	LU	-	N/A	N/A	N/A
5	Snake Rivery Pottery	LU	-	N/A	N/A	N/A
6	South Forks JointVenture/Lowline Canal	LU	-	N/A	N/A	N/A
7	Tamarack Energy Partnership	LU	-	4.942		
8	Tasco - Nampa	OS	-	N/A	N/A	N/A
9	Ted S. Sorenson/Tiber Dam	LU	-	N/A	N/A	N/A
10	Thousand Spring Wind Park	LU	-	N/A	N/A	N/A
11	Tuana Gulch Wind Park	LU	-	N/A	N/A	N/A
12	Tuana Springs Expansion	LU	-	N/A	N/A	N/A
13	Twin Falls Energy/Lowline Midway Hydro	LU	-	N/A	N/A	N/A
14	White Water Ranch	LU	-	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	William Arkoosh/Littlewood	LU	-	N/A	N/A	N/A
2	Willis and Betty Deveny/Shingle Creek	LU	-	N/A	N/A	N/A
3	Wilson Power Company	LU	-	N/A	N/A	N/A
4	Yahoo Creek Wind Park	LU	-	N/A	N/A	N/A
5	New Wind Projects Scheduled Energy	LU	-	N/A	N/A	N/A
6	Other Purchased Power					
7	Arizona Public Service Co.	SF	WSPP	N/A	N/A	N/A
8	Avista Corp.	SF	T-12	N/A	N/A	N/A
9	Avista Corp.	SF	WSPP	N/A	N/A	N/A
10	Avista Corp.	OS	WSPP	N/A	N/A	N/A
11	Barclays Bank PLC	SF	WSPP	N/A	N/A	N/A
12	Barclays Bank PLC	OS	-	N/A	N/A	N/A
13	Black Hills Power Inc.	SF	WSPP	N/A	N/A	N/A
14	Bonneville Power Administration	OS	WSPP	N/A	N/A	N/A
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Bonneville Power Administration	SF	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	Calpine Energy Services, L.P.	SF	WSPP	N/A	N/A	N/A
5	Cargill Power Markets LLC	SF	WSPP	N/A	N/A	N/A
6	Chelan Co PUD	SF	WSPP	N/A	N/A	N/A
7	Citigroup Energy Inc.	SF	WSPP	N/A	N/A	N/A
8	Citigroup Energy Inc.	OS	-	N/A	N/A	N/A
9	Clatskanie PUD	SF	WSPP	N/A	N/A	N/A
10	Constellation Energy Commodities Group	SF	WSPP	N/A	N/A	N/A
11	DB Energy Trading LLC	SF	WSPP	N/A	N/A	N/A
12	Douglas County PUD	SF	WSPP	N/A	N/A	N/A
13	EDF Trading North America, LLC	SF	WSPP	N/A	N/A	N/A
14	El Paso Electric Company	SF	WSPP	N/A	N/A	N/A
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Eugene Water & Electric Board	SF	WSPP	N/A	N/A	N/A
2	Glendale Power Marketing	SF	WSPP	N/A	N/A	N/A
3	Grant CO Public Utility District #2 --	SF	WSPP	N/A	N/A	N/A
4	IBERDROLA RENEWABLES, Inc.	SF	WSPP	N/A	N/A	N/A
5	J.P. Morgan Ventures Energy Corporatio	SF	WSPP	N/A	N/A	N/A
6	JPMorgan Chase Bank, N.A.	OS	-	N/A	N/A	N/A
7	Jefferies Bache	OS	-	N/A	N/A	N/A
8	Los Alamos County Utilities	SF	WSPP	N/A	N/A	N/A
9	Macquarie Cook Power Inc.	SF	WSPP	N/A	N/A	N/A
10	Macquarie Cook Power Inc.	OS	-	N/A	N/A	N/A
11	Morgan Stanley Capital Group Inc.	SF	V6-62	N/A	N/A	N/A
12	Morgan Stanley Capital Group Inc.	SF	V6-62	N/A	N/A	N/A
13	NaturEner USA, LLC	SF	WSPP	N/A	N/A	N/A
14	Nevada Power Co, DBA NV Energy	SF	WSPP	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	NextEra Energy Power Marketing, LLC	SF	WSPP	N/A	N/A	N/A
2	NorthWestern Energy	SF	T-7	N/A	N/A	N/A
3	NorthWestern Energy	SF	WSPP	N/A	N/A	N/A
4	PacifiCorp Inc.	SF	T-13	N/A	N/A	N/A
5	PacifiCorp Inc.	SF	WSPP	N/A	N/A	N/A
6	PacifiCorp Inc.	SF	WSPP	N/A	N/A	N/A
7	PacifiCorp Inc.	OS	WSPP	N/A	N/A	N/A
8	Portland General Electric Company	SF	T-14	N/A	N/A	N/A
9	Portland General Electric Company	SF	WSPP	N/A	N/A	N/A
10	Portland General Electric Company	SF	WSPP	N/A	N/A	N/A
11	Powerex Corp.	SF	WSPP	N/A	N/A	N/A
12	Powerex Corp.	SF	WSPP	N/A	N/A	N/A
13	PPL EnergyPlus, LLC	IF	WSPP	N/A	N/A	N/A
14	PPL EnergyPlus, LLC	SF	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)	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	Public Service Company of New Mexico	SF	WSPP	N/A	N/A	N/A
2	Puget Sound Energy, Inc.	SF	T-9	N/A	N/A	N/A
3	Puget Sound Energy, Inc.	SF	WSPP	N/A	N/A	N/A
4	Puget Sound Energy, Inc.	SF	WSPP	N/A	N/A	N/A
5	Rainbow Energy Marketing Corporation	SF	WSPP	N/A	N/A	N/A
6	San Diego Gas and Electric	SF	WSPP	N/A	N/A	N/A
7	Seattle City Light	SF	WSPP	N/A	N/A	N/A
8	Seattle City Light	SF	WSPP	N/A	N/A	N/A
9	Shell Energy North America (US), L.P.	SF	WSPP	N/A	N/A	N/A
10	Shell Energy North America (US), L.P.	OS	-	N/A	N/A	N/A
11	Sierra Pacific Power Co., dba NV Energ	SF	T-55	N/A	N/A	N/A
12	Sierra Pacific Power Co., dba NV Energ	SF	WSPP	N/A	N/A	N/A
13	Sierra Pacific Power Co., dba NV Energ	SF	WSPP	N/A	N/A	N/A
14	Sierra Pacific Power Co., dba NV Energ	OS	WSPP	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Snohomish County PUD	SF	WSPP	N/A	N/A	N/A
2	Southern California Edison	SF	WSPP	N/A	N/A	N/A
3	Southwestern Public Service Company	SF	WSPP	N/A	N/A	N/A
4	Tacoma Power	SF	WSPP	N/A	N/A	N/A
5	The Energy Authority, Inc.	SF	WSPP	N/A	N/A	N/A
6	TransAlta Energy Marketing (U.S.) Inc.	SF	WSPP	N/A	N/A	N/A
7	TransAlta Energy Marketing (U.S.) Inc.	SF	WSPP	N/A	N/A	N/A
8	Tri-State Generation and Transmission	SF	WSPP	N/A	N/A	N/A
9	Tucson Electric Power Company	SF	WSPP	N/A	N/A	N/A
10	Wells Fargo Authority, N.A.	OS	-	N/A	N/A	N/A
11	Western Area Power Administration	SF	WSPP	N/A	N/A	N/A
12	Raft River Energy I LLC	LU	-	N/A	N/A	N/A
13	Telocaset Wind Power Partners LLC	LU	APP-A	N/A	N/A	N/A
14	Net Metering Customers	OS	-	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Oregon Solar Customers	OS	-	N/A	N/A	N/A
2	Macquarie Energy LLC	AD	WSPP	N/A	N/A	N/A
3	Power Exchanges					
4	Benton Co Public Utility District #1	EX	-	-	-	-
5	Bonneville Power Administration	EX	-	-	-	-
6	NorthWestern Energy	EX	-	-	-	-
7	PacifiCorp Inc.	EX	-	-	-	-
8	Puget Sound Energy, Inc.	EX	-	-	-	-
9	Sierra Pacific Power Co., dba NV Energ	EX	-	-	-	-
10	Utah Associated Municipal Power System	EX	-	-	-	-
11	Clatskanie PUD	EX	153	-	-	-
12	Sierra Pacific Power Co., dba NV Energ	EX	WSPP	-	-	-
13	PacifiCorp Inc	EX	WSPP	-	-	-
14	Other Transactions					
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Acct Valuation-Clatskanie PUD Exchange		-	-	-	-
2	Write-Off (Lehman Brothers)		-	-	-	-
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
173				3,741		3,741	2
3,517			155,672	99,501		255,173	3
45,167				2,483,800		2,483,800	4
9,891				325,916		325,916	5
8,994				504,286		504,286	6
							7
336				22,007		22,007	8
1,323				89,760		89,760	9
1,329				90,187		90,187	10
5,504				498,646		498,646	11
793				54,831		54,831	12
45,701				1,880,363		1,880,363	13
27,866				1,494,916		1,494,916	14
2,777,898	602,391	680,849	2,815,124	146,504,839	7,553,786	156,873,749	

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)	
60,804				5,025,974		5,025,974	1
2,295				79,729		79,729	2
							3
24,118				1,079,424		1,079,424	4
327				25,893		25,893	5
58				4,046		4,046	6
1,532				110,715		110,715	7
3,490				294,206		294,206	8
342			17,500	9,669		27,169	9
							10
14,120				695,077		695,077	11
4,033				288,572		288,572	12
9,575				471,800		471,800	13
15,517				847,439		847,439	14
2,777,898	602,391	680,849	2,815,124	146,504,839	7,553,786	156,873,749	

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
9,689				520,129		520,129	1
5,022				333,058		333,058	2
11,237				764,612		764,612	3
584			26,796	16,532		43,328	4
816				11,516		11,516	5
1,539				105,819		105,819	6
10,048				976,820		976,820	7
3,139				238,020		238,020	8
1,087				15,461		15,461	9
24,732				1,214,017		1,214,017	10
23,680				1,357,141		1,357,141	11
-32				-16,371		-16,371	12
26,958				1,191,124		1,191,124	13
22,984				1,569,320		1,569,320	14
2,777,898	602,391	680,849	2,815,124	146,504,839	7,553,786	156,873,749	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
1,615				116,960		116,960	1
41,991				2,788,304		2,788,304	2
20,582				1,003,804		1,003,804	3
44,465				2,454,028		2,454,028	4
12,376				933,162		933,162	5
77,631				4,454,339		4,454,339	6
1,422				80,643		80,643	7
4,026				298,796		298,796	8
633				35,123		35,123	9
3,276				251,302		251,302	10
3,841				313,305		313,305	11
9,205				599,368		599,368	12
1,486				113,045		113,045	13
288				24,468		24,468	14
2,777,898	602,391	680,849	2,815,124	146,504,839	7,553,786	156,873,749	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
6,631				423,980		423,980	1
8,737				619,500		619,500	2
28,257				1,469,468		1,469,468	3
3,502				233,621		233,621	4
57,414				3,696,680		3,696,680	5
39,112				1,790,027		1,790,027	6
459				31,240		31,240	7
33,718				1,382,867		1,382,867	8
							9
7,076				166,007		166,007	10
25,601				485,901		485,901	11
25,063				2,752,182		2,752,182	12
58,964				4,846,169		4,846,169	13
7,374			486,150	181,396		667,546	14
2,777,898	602,391	680,849	2,815,124	146,504,839	7,553,786	156,873,749	

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)	
30,261				1,371,177		1,371,177	1
850				18,180		18,180	2
856				48,791		48,791	3
784				59,078		59,078	4
							5
1,664				109,773		109,773	6
3,715				248,306		248,306	7
1,173				17,307		17,307	8
4,692				279,049		279,049	9
1,458				106,175		106,175	10
10,247			552,508	289,896		842,404	11
24,934				1,101,093		1,101,093	12
79,969				5,012,242		5,012,242	13
21,263				820,346		820,346	14
2,777,898	602,391	680,849	2,815,124	146,504,839	7,553,786	156,873,749	

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)	
23,842				1,224,987		1,224,987	1
							2
1,941				153,670		153,670	3
2,634				171,411		171,411	4
364				24,629		24,629	5
28,067				2,009,238		2,009,238	6
32,725			1,576,498	1,222,917		2,799,415	7
143				2,168		2,168	8
29,729				1,520,185		1,520,185	9
30,024				1,283,708		1,283,708	10
26,287				1,022,303		1,022,303	11
82,103				5,270,518		5,270,518	12
8,950				536,979		536,979	13
679				44,717		44,717	14
2,777,898	602,391	680,849	2,815,124	146,504,839	7,553,786	156,873,749	

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)	
4,294				306,445		306,445	1
1,015				70,109		70,109	2
26,648				1,823,974		1,823,974	3
59,972				4,942,689		4,942,689	4
792							5
							6
26,690				994,099		994,099	7
24				738		738	8
3,369				89,845		89,845	9
					278,412	278,412	10
415				8,763		8,763	11
					43,340	43,340	12
4,102				124,785		124,785	13
					524,683	524,683	14
2,777,898	602,391	680,849	2,815,124	146,504,839	7,553,786	156,873,749	

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)	
125,529				3,588,046		3,588,046	1
990				27,950		27,950	2
25,200				1,118,900		1,118,900	3
31,024				862,192		862,192	4
38,435				1,177,579		1,177,579	5
206				2,952		2,952	6
14,071				396,889		396,889	7
					163,244	163,244	8
427				3,574		3,574	9
1,722				56,342		56,342	10
3,200				85,128		85,128	11
1,601				40,036		40,036	12
3,350				91,601		91,601	13
537				8,000		8,000	14
2,777,898	602,391	680,849	2,815,124	146,504,839	7,553,786	156,873,749	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
11,275				263,134		263,134	1
63				3,266		3,266	2
1,986				50,865		50,865	3
94,000				2,705,042		2,705,042	4
63,807				5,487,618		5,487,618	5
					572,658	572,658	6
					6,320,112	6,320,112	7
2							8
69,101				2,717,535		2,717,535	9
					72,038	72,038	10
3,252				56,697		56,697	11
90				3,600		3,600	12
1				36		36	13
200				9,000		9,000	14
2,777,898	602,391	680,849	2,815,124	146,504,839	7,553,786	156,873,749	

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)	
29,575				1,262,442		1,262,442	1
42				1,267		1,267	2
15				525		525	3
218				6,526		6,526	4
92				3,120		3,120	5
13,266				434,748		434,748	6
					139,138	139,138	7
42				1,270		1,270	8
37,330				826,882		826,882	9
50				900		900	10
31,577				1,382,689		1,382,689	11
630				29,185		29,185	12
103,584				9,555,624		9,555,624	13
50,783				1,351,475		1,351,475	14
2,777,898	602,391	680,849	2,815,124	146,504,839	7,553,786	156,873,749	

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)	
187				8,386		8,386	1
52				1,587		1,587	2
24,348				690,070		690,070	3
225				7,050		7,050	4
24,497				1,072,745		1,072,745	5
1				7		7	6
9,954				273,191		273,191	7
20				520		520	8
28,519				720,324		720,324	9
					112,078	112,078	10
22				669		669	11
9,039				305,532		305,532	12
5				24		24	13
					6,808	6,808	14
2,777,898	602,391	680,849	2,815,124	146,504,839	7,553,786	156,873,749	

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)	
4,492				114,955		114,955	1
6,579				183,947		183,947	2
248				4,359		4,359	3
2,168				75,276		75,276	4
2,598				78,536		78,536	5
2,448				79,171		79,171	6
40				560		560	7
90				9,000		9,000	8
145				1,576		1,576	9
					68,756	68,756	10
1				36		36	11
63,489				3,781,365		3,781,365	12
310,955				16,772,667		16,772,667	13
639				51,605		51,605	14
2,777,898	602,391	680,849	2,815,124	146,504,839	7,553,786	156,873,749	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
106				3,375		3,375	1
50				2,000		2,000	2
							3
	1						4
	60,085						5
		2,946					6
	165,922	269,181					7
	18						8
		5,455					9
	24						10
	84,917	111,843					11
	228,424	228,424					12
	63,000	63,000					13
							14
2,777,898	602,391	680,849	2,815,124	146,504,839	7,553,786	156,873,749	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
					-716,681	-716,681	1
					-30,800	-30,800	2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
2,777,898	602,391	680,849	2,815,124	146,504,839	7,553,786	156,873,749	

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

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

Schedule Page: 326.1 Line No.: 9 Column: e
Unavailable

Schedule Page: 326.1 Line No.: 9 Column: f
Unavailable

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

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

Schedule Page: 326.2 Line No.: 9 Column: b
Non Firm Purchases

Schedule Page: 326.2 Line No.: 12 Column: a
ISDA Master Agreement with Shell Energy North America dated November 1, 2009

Schedule Page: 326.2 Line No.: 14 Column: a
Ida West, a subsidiary of Idaho Power Company, has partial ownership of these projects.

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

Schedule Page: 326.4 Line No.: 14 Column: e
Unavailable

Schedule Page: 326.4 Line No.: 14 Column: f
Unavailable

Schedule Page: 326.5 Line No.: 8 Column: b
Non Firm Purchases

Schedule Page: 326.5 Line No.: 11 Column: e
Unavailable

Schedule Page: 326.5 Line No.: 11 Column: f
Unavailable

Schedule Page: 326.6 Line No.: 6 Column: a
Ida West, a subsidiary of Idaho Power Company, has partial ownership of these projects.

Schedule Page: 326.6 Line No.: 7 Column: a
The Tamarack Energy Partnership demand readings are taken from an electronic demand recorder provided by Idaho Power Co. The actual demand is not used in determining the cost of energy.

Schedule Page: 326.6 Line No.: 7 Column: e
Unavailable

Schedule Page: 326.6 Line No.: 7 Column: f
Unavailable

Schedule Page: 326.6 Line No.: 8 Column: b
Non Firm Purchases

Schedule Page: 326.7 Line No.: 3 Column: a
Ida West, a subsidiary of Idaho Power Company, has partial ownership of these projects.

Schedule Page: 326.7 Line No.: 5 Column: b
Energy scheduled in December 2010, booked in January 2011

Schedule Page: 326.7 Line No.: 10 Column: b
Financial Transmission Losses

Schedule Page: 326.7 Line No.: 12 Column: b
ISDA Master Agreement with Barclays Bank PLC dated March 2, 2011

Schedule Page: 326.7 Line No.: 14 Column: b
Financial Transmission Losses

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

Non Firm Purchases

Schedule Page: 326.8 Line No.: 8 Column: b

ISDA Master Agreement with Citigroup Energy PLC dated March 7, 2011

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

ISDA Master Agreement with JP Morgan Chase Bank dated November 4, 2005

Schedule Page: 326.9 Line No.: 7 Column: b

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

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

ISDA Master Agreement with Macquarie Energy PLC dated April 12, 2011

Schedule Page: 326.9 Line No.: 12 Column: b

Non Firm Purchases

Schedule Page: 326.10 Line No.: 5 Column: b

Non Firm Purchases

Schedule Page: 326.10 Line No.: 7 Column: b

Financial Transmission Losses

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

Non Firm Purchases

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

ISDA Master Agreement with Shell Energy North America dated November 1, 2009

Schedule Page: 326.11 Line No.: 13 Column: b

Non Firm Purchases

Schedule Page: 326.11 Line No.: 14 Column: b

Financial Transmission Losses

Schedule Page: 326.12 Line No.: 10 Column: b

ISDA Master Agreement with Wells Fargo Bank, N.A., dated March 1, 2006

Schedule Page: 326.12 Line No.: 12 Column: b

Unavailable

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

Schedule 84 Net Metering

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

Schedule 88 Oregon Solar

Schedule Page: 326.13 Line No.: 2 Column: b

December 2010 adjustment

Schedule Page: 326.13 Line No.: 4 Column: b

Scheduled losses not removed with loss transactions

Schedule Page: 326.13 Line No.: 5 Column: b

Scheduled losses not removed with loss transactions

Schedule Page: 326.13 Line No.: 6 Column: b

Scheduled losses not removed with loss transactions

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

Scheduled losses not removed with loss transactions

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

Scheduled losses not removed with loss transactions

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

Scheduled losses not removed with loss transactions

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

Scheduled losses not removed with loss transactions

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Bonneville Power Administration - OTEC	Bonneville Power Administration	Oregon Trails Electric Co-op	FNO
2	Bonneville Power Administration - USBR	Bonneville Power Administration	United States Bureau of Reclamati	FNO
3	Bonneville Power Administration - Raft	Bonneville Power Administration	Raft River Electric Co-op	FNO
4	Bonneville Power Administration - PF	Bonneville Power Administration	Priority Firm Customers	FNO
5	Milner Irrigation District	United States Bureau of Reclamati	Milner Irrigation District	OLF
6	Cargill	Seattle City Light	Bonneville Power Administration	OS
7	PacifiCorp	PacifiCorp West	PacifiCorp West	FNO
8	United States Bureau of Indian Affairs	Bonneville Power Administration	United States Bureau of Indian Af	OS
9	PacifiCorp	PacifiCorp West	PacifiCorp West	OS
10	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp East	NF
11	BC Hydro Powerex	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
12	BC Hydro Powerex	PacifiCorp East	NorthWestern/PacifiCorp East	NF
13	BC Hydro Powerex	PacifiCorp East	PacifiCorp East	NF
14	BC Hydro Powerex	PacifiCorp East	PacifiCorp West	NF
15	BC Hydro Powerex	PacifiCorp East	Bonneville Power Administration	NF
16	BC Hydro Powerex	PacifiCorp East	Avista	NF
17	BC Hydro Powerex	PacifiCorp East	Sierra Pacific Power	NF
18	BC Hydro Powerex	PacifiCorp East	PacifiCorp West	NF
19	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp East	NF
20	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
21	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp East	NF
22	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
23	BC Hydro Powerex	NorthWestern/PacifiCorp East	PacifiCorp West	NF
24	BC Hydro Powerex	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
25	BC Hydro Powerex	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
26	BC Hydro Powerex	NorthWestern/PacifiCorp East	Sierra Pacific Power	SFP
27	BC Hydro Powerex	PacifiCorp East	NorthWestern/PacifiCorp East	NF
28	BC Hydro Powerex	PacifiCorp East	PacifiCorp East	NF
29	BC Hydro Powerex	PacifiCorp East	NorthWestern/PacifiCorp East	NF
30	BC Hydro Powerex	PacifiCorp East	PacifiCorp West	NF
31	BC Hydro Powerex	PacifiCorp East	PacifiCorp West	NF
32	BC Hydro Powerex	PacifiCorp East	Bonneville Power Administration	NF
33	BC Hydro Powerex	PacifiCorp East	Avista	NF
34	BC Hydro Powerex	PacifiCorp East	Sierra Pacific Power	NF
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

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

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

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

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

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

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

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

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

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

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

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

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

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

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	PPL Energy Plus	Avista	PacifiCorp East	NF
2	PPL Energy Plus	Avista	Bonneville Power Administration	NF
3	Puget Sound Energy	PacifiCorp East	Bonneville Power Administration	NF
4	Puget Sound Energy	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
5	Puget Sound Energy	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
6	Puget Sound Energy	Bonneville Power Administration	Sierra Pacific Power	NF
7	Puget Sound Energy	Avista	Idaho Power Company	NF
8	Rainbow Energy Marketing	PacifiCorp East	NorthWestern/PacifiCorp East	NF
9	Rainbow Energy Marketing	PacifiCorp East	NorthWestern/PacifiCorp East	NF
10	Rainbow Energy Marketing	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
11	Rainbow Energy Marketing	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
12	Rainbow Energy Marketing	PacifiCorp East	Sierra Pacific Power	NF
13	Rainbow Energy Marketing	PacifiCorp East	Sierra Pacific Power	SFP
14	Rainbow Energy Marketing	PacifiCorp West	PacifiCorp East	NF
15	Rainbow Energy Marketing	PacifiCorp West	PacifiCorp East	SFP
16	Rainbow Energy Marketing	PacifiCorp West	PacifiCorp East	SFP
17	Rainbow Energy Marketing	NorthWestern/PacifiCorp East	PacifiCorp East	NF
18	Rainbow Energy Marketing	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
19	Rainbow Energy Marketing	NorthWestern/PacifiCorp East	PacifiCorp East	NF
20	Rainbow Energy Marketing	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
21	Rainbow Energy Marketing	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
22	Rainbow Energy Marketing	NorthWestern/PacifiCorp East	Sierra Pacific Power	SFP
23	Rainbow Energy Marketing	Avista	PacifiCorp East	NF
24	Rainbow Energy Marketing	Avista	PacifiCorp East	SFP
25	Rainbow Energy Marketing	Avista	PacifiCorp East	NF
26	Rainbow Energy Marketing	Avista	PacifiCorp East	SFP
27	Rainbow Energy Marketing	Avista	Sierra Pacific Power	NF
28	Rainbow Energy Marketing	Avista	Sierra Pacific Power	SFP
29	Rainbow Energy Marketing	Idaho Power Company	PacifiCorp East	NF
30	Seattle City Light			LFP
31	Shell Energy	PacifiCorp East	Bonneville Power Administration	NF
32	Shell Energy	PacifiCorp East	PacifiCorp East	NF
33	Shell Energy	PacifiCorp East	Bonneville Power Administration	NF
34	Shell Energy	PacifiCorp East	Sierra Pacific Power	NF
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

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

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

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

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

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

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

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

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
5				368,297	368,297	1
5				189,508	189,508	2
5				205,046	205,046	3
5				907,088	907,088	4
Legacy	Minidoka, Idaho	Various in Idaho		8,322	8,322	5
10				388,704	388,704	6
5				2,094	2,094	7
Legacy	LaGrande, Oregon	Various in Idaho		14,238	14,238	8
Legacy	JBSN	ENPR				9
5	AVAT.NWMT	BORA		92	92	10
5	AVAT.NWMT	M345		30	30	11
5	BORA	BPAT.NWMT		855	855	12
5	BORA	BRDY		179	179	13
5	BORA	JBSN		490	490	14
5	BORA	LAGRANDE		9,866	9,866	15
5	BORA	LOLO		99	99	16
5	BORA	M345		3,546	3,546	17
5	BORA	M500		2,314	2,314	18
5	BPAT.NWMT	BORA		3,310	3,310	19
5	BPAT.NWMT	BORA		3,688	3,688	20
5	BPAT.NWMT	BRDY		2,380	2,380	21
5	BPAT.NWMT	BRDY		8,830	8,830	22
5	BPAT.NWMT	JBSN		95	95	23
5	BPAT.NWMT	LAGRANDE		397	397	24
5	BPAT.NWMT	M345		664	664	25
5	BPAT.NWMT	M345		18,792	18,792	26
5	BRDY	AVAT.NWMT		102	102	27
5	BRDY	BORA		260	260	28
5	BRDY	BPAT.NWMT		154	154	29
5	BRDY	ENPR		80	80	30
5	BRDY	JBSN		90	90	31
5	BRDY	LAGRANDE		14,347	14,347	32
5	BRDY	LOLO		10	10	33
5	BRDY	M345		2,386	2,386	34
			0	**6,092,216**	**6,092,216**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
5	BRDY	M345		1,848	1,848	1
5	BRDY	M500		1,281	1,281	2
5	ENPR	BORA		219,615	219,615	3
5	ENPR	BORA		1,433	1,433	4
5	ENPR	BRDY		19,008	19,008	5
5	ENPR	BRDY		3,642	3,642	6
5	ENPR	JBSN		211	211	7
5	ENPR	M345		1,127	1,127	8
5	ENPR	M345		32	32	9
5	GSHN	AVAT.NWMT		10	10	10
5	GSHN	BPAT.NWMT		523	523	11
5	GSHN	BRDY		667	667	12
5	GSHN	ENPR		83	83	13
5	GSHN	JBSN		544	544	14
5	GSHN	JEFF		35	35	15
5	GSHN	LAGRANDE		10,167	10,167	16
5	GSHN	M345		579	579	17
5	GSHN	M500		796	796	18
5	HCPR	BPAT.NWMT		149	149	19
5	HCPR	LAGRANDE		3,056	3,056	20
5	JBSN	BORA		20	20	21
5	JBSN	BPAT.NWMT		36	36	22
5	JBSN	LAGRANDE		2,947	2,947	23
5	JBSN	M345		138	138	24
5	JBWT	BORA		35	35	25
5	JBWT	LAGRANDE		1,448	1,448	26
5	JBWT	M500		127	127	27
5	JEFF	BORA		6,317	6,317	28
5	JEFF	BRDY		746	746	29
5	JEFF	ENPR		53	53	30
5	JEFF	JBSN		88	88	31
5	JEFF	LAGRANDE		400	400	32
5	JEFF	M345		103	103	33
5	LAGRANDE	BORA		54,378	54,378	34
			0	**6,092,216**	**6,092,216**	

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
5	LAGRANDE	BORA		799	799	1
5	LAGRANDE	BRDY		12,461	12,461	2
5	LAGRANDE	BRDY		2,482	2,482	3
5	LAGRANDE	JBSN		1,847	1,847	4
5	LAGRANDE	M345		11,056	11,056	5
5	LAGRANDE	M345		373	373	6
5	LOLO	BORA		11,424	11,424	7
5	LOLO	BRDY		1,165	1,165	8
5	LOLO	JBSN		168	168	9
5	LOLO	M345		3,569	3,569	10
5	M345	BPAT.NWMT		132	132	11
5	M345	BRDY		80	80	12
5	M345	LAGRANDE		2,001	2,001	13
5	MDSK	BPAT.NWMT		175	175	14
5	MDSK	LAGRANDE		1,272	1,272	15
5	OBBLPR	BPAT.NWMT		204	204	16
5	OBBLPR	LAGRANDE		1,738	1,738	17
5	BORA	M345		2,250	2,250	18
5	JBSN	LAGRANDE		10	10	19
5	LAGRANDE	BORA		25	25	20
5	LAGRANDE	JBSN		60	60	21
5	LAGRANDE	LAGRANDE		3,005	3,005	22
5	LAGRANDE	M345		1,542	1,542	23
5	LOLO	LAGRANDE		7,115	7,115	24
5	LOLO	LAGRANDE		768	768	25
5	LOLO	M345		324	324	26
5	BORA	AVAT.NWMT		525	525	27
5	BORA	BPAT.NWMT		1,420	1,420	28
5	BORA	ENPR		820	820	29
5	BORA	JBSN		996	996	30
5	BORA	LAGRANDE		10,089	10,089	31
5	BORA	LOLO		249	249	32
5	BORA	M345		8,416	8,416	33
5	BORA	M345		4,153	4,153	34
			0	**6,092,216**	**6,092,216**	

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
5	BPAT.NWMT	BORA		2,651	2,651	1
5	BPAT.NWMT	BORA		33,899	33,899	2
5	BPAT.NWMT	BRDY		25	25	3
5	BPAT.NWMT	JBSN		440	440	4
5	BPAT.NWMT	JBSN		1,200	1,200	5
5	BPAT.NWMT	LAGRANDE		5	5	6
5	BPAT.NWMT	M345		2,791	2,791	7
5	BPAT.NWMT	M345		43,719	43,719	8
5	BRDY	BORA		322	322	9
5	BRDY	BORA		504	504	10
5	BRDY	ENPR		63	63	11
5	BRDY	LAGRANDE		112	112	12
5	BRDY	LAGRANDE		600	600	13
5	BRDY	M345		932	932	14
5	BRDY	M345		64	64	15
5	ENPR	BORA		69,699	69,699	16
5	ENPR	BORA		60,810	60,810	17
5	ENPR	M345		8,765	8,765	18
5	ENPR	M345		1,392	1,392	19
5	HCPR	BORA		400	400	20
5	HCPR	M345		800	800	21
5	HCPR	M345		1,600	1,600	22
5	JBSN	BPAT.NWMT		3,200	3,200	23
5	JBSN	LAGRANDE		148	148	24
5	JBSN	M345		592	592	25
5	JBSN	M345		408	408	26
5	JEFF	BORA		320	320	27
5	JEFF	M345		928	928	28
5	LAGRANDE	BORA		2,346	2,346	29
5	LAGRANDE	BORA		1,454	1,454	30
5	LAGRANDE	JBSN		306	306	31
5	LAGRANDE	LOLO		238	238	32
5	LAGRANDE	M345		11,482	11,482	33
5	LAGRANDE	M345		17,606	17,606	34
			0	**6,092,216**	**6,092,216**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
5	LOLO	BORA		1,142	1,142	1
5	LOLO	M345		5,988	5,988	2
5	LYPK	BORA		10,724	10,724	3
5	LYPK	BORA		37,726	37,726	4
5	LYPK	BPAT.NWMT		1,563	1,563	5
5	LYPK	BRDY		667	667	6
5	LYPK	JEFF		173	173	7
5	LYPK	LAGRANDE		14,243	14,243	8
5	LYPK	LAGRANDE		1,664	1,664	9
5	LYPK	LOLO		100	100	10
5	LYPK	LOLO		200	200	11
5	LYPK	M345		64,772	64,772	12
5	LYPK	M345		243,254	243,254	13
5	M345	LAGRANDE		275	275	14
5	MDSK	LOLO		200	200	15
5	OBBLPR	BORA		1,000	1,000	16
5	OBBLPR	BORA		1,000	1,000	17
5	OBBLPR	LAGRANDE		410	410	18
5	OBBLPR	LAGRANDE		1,808	1,808	19
5	OBBLPR	M345		320	320	20
5	OBBLPR	M345		480	480	21
5						22
5	BORA	LAGRANDE		361	361	23
5	BRDY	LAGRANDE		57	57	24
5	BRDY	M345		24	24	25
5	LAGRANDE	BORA		5,027	5,027	26
5	LAGRANDE	M345		4,104	4,104	27
5	LOLO	M345		380	380	28
5	M345	LAGRANDE		381	381	29
5	AVAT.NWMT	BORA		544	544	30
5	AVAT.NWMT	BRDY		140	140	31
5	AVAT.NWMT	LAGRANDE		132	132	32
5	AVAT.NWMT	M345		3,663	3,663	33
5	BORA	LAGRANDE		66	66	34
			0	**6,092,216**	**6,092,216**	

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
5	BORA	M345		8,522	8,522	1
5	BPAT.NWMT	BORA		371	371	2
5	BPAT.NWMT	BRDY		1,237	1,237	3
5	BPAT.NWMT	LAGRANDE		210	210	4
5	BPAT.NWMT	M345		756	756	5
5	BRDY	AVAT.NWMT		46	46	6
5	BRDY	BORA		62	62	7
5	BRDY	BPAT.NWMT		119	119	8
5	BRDY	JBSN		99	99	9
5	BRDY	LAGRANDE		19,275	19,275	10
5	BRDY	LOLO		100	100	11
5	BRDY	M345		8,148	8,148	12
5	BRDY	M345		1,981	1,981	13
5	ENPR	BRDY		1,128	1,128	14
5	ENPR	M345		180	180	15
5	JBSN	LAGRANDE		20	20	16
5	JBSN	M345		29	29	17
5	JEFF	BORA		5,996	5,996	18
5	JEFF	BRDY		6,680	6,680	19
5	JEFF	JBSN		250	250	20
5	JEFF	LAGRANDE		5,698	5,698	21
5	JEFF	LOLO		60	60	22
5	JEFF	M345		21,705	21,705	23
5	LAGRANDE	BORA		3,085	3,085	24
5	LAGRANDE	BRDY		8,183	8,183	25
5	LAGRANDE	ENPR		5	5	26
5	LAGRANDE	JBSN		65	65	27
5	LAGRANDE	M345		2,075	2,075	28
5	LOLO	BORA		2,335	2,335	29
5	LOLO	BRDY		2,292	2,292	30
5	LOLO	LAGRANDE		411	411	31
5	LOLO	M345		1,983	1,983	32
5	M345	JEFF		114	114	33
5	M345	LAGRANDE		1,597	1,597	34
			0	**6,092,216**	**6,092,216**	

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
5	0	0				1
5	BORA	ENPR		8,014	8,014	2
5	BORA	GSHN		3,740	3,740	3
5	BORA	KPRT		390,968	390,968	4
5	BORA	KPRT		403,551	403,551	5
5	BORA	LAGRANDE		1,621	1,621	6
5	BORA	M345		2,285	2,285	7
5	BORA	M345		4,032	4,032	8
5	BRDY	BRDY		1,616	1,616	9
5	ENPR	BORA		29,752	29,752	10
5	ENPR	LAGRANDE		682	682	11
5	JBSN	BORA		2,675	2,675	12
5	JBWT	BORA		61,027	61,027	13
5	JBWT	BRDY		54,685	54,685	14
5	JBWT	BRDY		381,175	381,175	15
5	JBWT	ENPR		1,153	1,153	16
5	JBWT	LAGRANDE		4,211	4,211	17
5	JBWT	M500		906,776	906,776	18
5	LAGRANDE	BORA		37,083	37,083	19
5	LOLO	BORA		95,641	95,641	20
5	LOLO	ENPR		921	921	21
5	JEFF	LAGRANDE		580	580	22
5	BRDY	BORA		724	724	23
5	BRDY	JBSN		150	150	24
5	BRDY	LAGRANDE		5,514	5,514	25
5	BRDY	LOLO		964	964	26
5	JEFF	BORA		79	79	27
5	JEFF	BRDY		2,086	2,086	28
5	JEFF	JBSN		420	420	29
5	JEFF	LAGRANDE		1,259	1,259	30
5	LAGRANDE	BORA		526	526	31
5	LAGRANDE	BRDY		216	216	32
5	LAGRANDE	JBSN		60	60	33
5	LOLO	BORA		495	495	34
			0	**6,092,216**	**6,092,216**	

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
5	LOLO	BRDY		150	150	1
5	LOLO	LAGRANDE		937	937	2
5	BRDY	LAGRANDE		180	180	3
5	GSHN	LAGRANDE		155	155	4
5	JEFF	LAGRANDE		15	15	5
5	LAGRANDE	M345		134	134	6
5	LOLO	IPCOLOSS		1	1	7
5	BORA	AVAT.NWMT		200	200	8
5	BORA	JEFF		800	800	9
5	BPAT.NWMT	BORA		13,760	13,760	10
5	BPAT.NWMT	BRDY		16,074	16,074	11
5	BRDY	M345		172	172	12
5	BRDY	M345		2,081	2,081	13
5	ENPR	BRDY		1,623	1,623	14
5	ENPR	BRDY		348	348	15
5	JBSN	BRDY		1,568	1,568	16
5	JEFF	BORA		7,980	7,980	17
5	JEFF	BORA		8,109	8,109	18
5	JEFF	BRDY		40	40	19
5	JEFF	BRDY		4,093	4,093	20
5	JEFF	M345		505	505	21
5	JEFF	M345		23,673	23,673	22
5	LOLO	BORA		9,934	9,934	23
5	LOLO	BORA		2,501	2,501	24
5	LOLO	BRDY		3,017	3,017	25
5	LOLO	BRDY		1,050	1,050	26
5	LOLO	M345		400	400	27
5	LOLO	M345		2,250	2,250	28
5	OBBLPR	BRDY		400	400	29
5	0	0				30
5	BORA	LAGRANDE		25	25	31
5	BRDY	BORA		192	192	32
5	BRDY	LAGRANDE		5,375	5,375	33
5	BRDY	M345		468	468	34
			0	**6,092,216**	**6,092,216**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
5	JEFF	BORA		200	200	1
5	JEFF	LAGRANDE		77	77	2
5	LAGRANDE	BORA		13	13	3
5	LAGRANDE	M345		2,231	2,231	4
5	LOLO	BORA		25	25	5
5	LYPK	BORA		12	12	6
5	LYPK	BRDY		50	50	7
5	LYPK	LAGRANDE		174	174	8
5	M345	BORA		180	180	9
5	M345	BRDY		100	100	10
5	M345	LAGRANDE		3,533	3,533	11
5	M345	LOLO		68	68	12
5	MDSK	BORA		400	400	13
5	MDSK	LAGRANDE		541	541	14
5	MDSK	LOLO		17	17	15
5	OBBLPR	BORA		300	300	16
5	OBBLPR	LAGRANDE		67	67	17
5	BORA	M345		6,360	6,360	18
5	BORA	M345		9,140	9,140	19
5	BRDY	M345		11,800	11,800	20
5	BRDY	M345		31,608	31,608	21
5	JEFF	M345		42,409	42,409	22
5	JEFF	M345		11,141	11,141	23
5	LAGRANDE	M345		34,496	34,496	24
5	LAGRANDE	M345		4,325	4,325	25
5	LOLO	BORA		48	48	26
5	LOLO	M345		35,267	35,267	27
5	LOLO	M345		7,424	7,424	28
5	M345	BORA		1,082	1,082	29
5	M345	JEFF		185	185	30
5	M345	LAGRANDE		3,458	3,458	31
5	M345	LOLO		225	225	32
5	GSHN	LAGRANDE		125	125	33
5	AVAT.NWMT	BRDY		95	95	34
			0	**6,092,216**	**6,092,216**	

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr) 04/13/2012	End of 2011/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
5	BPAT.NWMT	BRDY		398	398	1
5	LAGRANDE	BORA		1,274	1,274	2
5	LAGRANDE	BRDY		1,290	1,290	3
5	LAGRANDE	JBSN		265	265	4
5	BRDY	LAGRANDE		30	30	5
5	BORA	LAGRANDE		706	706	6
5	BPAT.NWMT	BORA		25	25	7
5	BPAT.NWMT	BRDY		75	75	8
5	BRDY	LAGRANDE		300	300	9
5	JEFF	BORA		25	25	10
5	LAGRANDE	BORA		6,588	6,588	11
5	LAGRANDE	BRDY		1,066	1,066	12
5	LAGRANDE	M345		488	488	13
5	LOLO	BORA		513	513	14
5	LOLO	BRDY		28	28	15
5	M345	LAGRANDE		398	398	16
5	OBBLPR	BORA		50	50	17
5	OBBLPR	LAGRANDE		48	48	18
5	BORA	M345		648	648	19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			0	**6,092,216**	**6,092,216**	

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

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
1,414,450	39,800		1,454,250	1
1,163,226	201,793		1,365,019	2
535,470	18,160		553,630	3
3,193,659	-205,841		2,987,818	4
	13,482		13,482	5
	208,649		208,649	6
7,475	1,362		8,837	7
54,639			54,639	8
	2,395		2,395	9
	387		387	10
	126		126	11
	3,601		3,601	12
	754		754	13
	2,064		2,064	14
	41,551		41,551	15
	417		417	16
	14,934		14,934	17
	9,745		9,745	18
	13,940		13,940	19
	15,532		15,532	20
	10,023		10,023	21
	37,188		37,188	22
	400		400	23
	1,672		1,672	24
	2,796		2,796	25
	79,143		79,143	26
	430		430	27
	1,095		1,095	28
	649		649	29
	337		337	30
	379		379	31
	60,423		60,423	32
	42		42	33
	10,049		10,049	34
6,368,919	**13,003,985**	**0**	**19,372,904**	

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

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	7,783		7,783	1
	5,395		5,395	2
	924,914		924,914	3
	6,035		6,035	4
	80,053		80,053	5
	15,338		15,338	6
	889		889	7
	4,746		4,746	8
	135		135	9
	42		42	10
	2,203		2,203	11
	2,809		2,809	12
	350		350	13
	2,291		2,291	14
	147		147	15
	42,819		42,819	16
	2,438		2,438	17
	3,352		3,352	18
	628		628	19
	12,870		12,870	20
	84		84	21
	152		152	22
	12,411		12,411	23
	581		581	24
	147		147	25
	6,098		6,098	26
	535		535	27
	26,604		26,604	28
	3,142		3,142	29
	223		223	30
	371		371	31
	1,685		1,685	32
	434		434	33
	229,014		229,014	34
6,368,919	**13,003,985**	**0**	**19,372,904**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

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

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	3,365		3,365	1
	52,480		52,480	2
	10,453		10,453	3
	7,779		7,779	4
	46,563		46,563	5
	1,571		1,571	6
	48,112		48,112	7
	4,906		4,906	8
	708		708	9
	15,031		15,031	10
	556		556	11
	337		337	12
	8,427		8,427	13
	737		737	14
	5,357		5,357	15
	859		859	16
	7,320		7,320	17
	5,535		5,535	18
	25		25	19
	61		61	20
	148		148	21
	12,137		12,137	22
	6,228		6,228	23
	28,738		28,738	24
	3,102		3,102	25
	1,309		1,309	26
	312		312	27
	844		844	28
	487		487	29
	592		592	30
	5,998		5,998	31
	148		148	32
	5,003		5,003	33
	2,469		2,469	34
6,368,919	**13,003,985**	**0**	**19,372,904**	

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

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	1,576		1,576	1
	20,153		20,153	2
	15		15	3
	262		262	4
	713		713	5
	3		3	6
	1,659		1,659	7
	25,991		25,991	8
	191		191	9
	300		300	10
	37		37	11
	67		67	12
	357		357	13
	554		554	14
	38		38	15
	41,436		41,436	16
	36,151		36,151	17
	5,211		5,211	18
	828		828	19
	238		238	20
	476		476	21
	951		951	22
	1,902		1,902	23
	88		88	24
	352		352	25
	243		243	26
	190		190	27
	552		552	28
	1,395		1,395	29
	864		864	30
	182		182	31
	141		141	32
	6,826		6,826	33
	10,467		10,467	34
6,368,919	**13,003,985**	**0**	**19,372,904**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

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

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	679		679	1
	3,560		3,560	2
	6,375		6,375	3
	22,428		22,428	4
	929		929	5
	397		397	6
	103		103	7
	8,467		8,467	8
	989		989	9
	59		59	10
	119		119	11
	38,507		38,507	12
	144,613		144,613	13
	163		163	14
	119		119	15
	594		594	16
	594		594	17
	244		244	18
	1,075		1,075	19
	190		190	20
	285		285	21
	4		4	22
	1,246		1,246	23
	197		197	24
	83		83	25
	17,356		17,356	26
	14,169		14,169	27
	1,312		1,312	28
	1,315		1,315	29
	1,937		1,937	30
	498		498	31
	470		470	32
	13,042		13,042	33
	235		235	34
6,368,919	**13,003,985**	**0**	**19,372,904**	

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

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	30,342		30,342	1
	1,321		1,321	2
	4,404		4,404	3
	748		748	4
	2,692		2,692	5
	164		164	6
	221		221	7
	424		424	8
	352		352	9
	68,628		68,628	10
	356		356	11
	29,011		29,011	12
	7,053		7,053	13
	4,016		4,016	14
	641		641	15
	71		71	16
	103		103	17
	21,348		21,348	18
	23,784		23,784	19
	890		890	20
	20,287		20,287	21
	214		214	22
	77,280		77,280	23
	10,984		10,984	24
	29,135		29,135	25
	18		18	26
	231		231	27
	7,388		7,388	28
	8,314		8,314	29
	8,161		8,161	30
	1,463		1,463	31
	7,060		7,060	32
	406		406	33
	5,686		5,686	34
6,368,919	**13,003,985**	**0**	**19,372,904**	

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

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	4		4	1
	27,861		27,861	2
	13,002		13,002	3
	1,359,206		1,359,206	4
				5
	5,635		5,635	6
	7,944		7,944	7
	14,017		14,017	8
	5,618		5,618	9
	103,433		103,433	10
	2,371		2,371	11
	9,300		9,300	12
	212,161		212,161	13
	190,113		190,113	14
	1,325,161		1,325,161	15
	4,008		4,008	16
	14,640		14,640	17
	3,152,421		3,152,421	18
	128,920		128,920	19
	332,497		332,497	20
	3,202		3,202	21
	1,311		1,311	22
	2,275		2,275	23
	471		471	24
	17,329		17,329	25
	3,030		3,030	26
	248		248	27
	6,556		6,556	28
	1,320		1,320	29
	3,957		3,957	30
	1,653		1,653	31
	679		679	32
	189		189	33
	1,556		1,556	34
6,368,919	**13,003,985**	**0**	**19,372,904**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

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

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	471		471	1
	2,945		2,945	2
	2,137		2,137	3
	1,841		1,841	4
	178		178	5
	1,591		1,591	6
	12		12	7
	513		513	8
	2,052		2,052	9
	35,296		35,296	10
	41,232		41,232	11
	441		441	12
	5,338		5,338	13
	4,163		4,163	14
	893		893	15
	4,022		4,022	16
	20,470		20,470	17
	20,801		20,801	18
	103		103	19
	10,499		10,499	20
	1,295		1,295	21
	60,724		60,724	22
	25,482		25,482	23
	6,415		6,415	24
	7,739		7,739	25
	2,693		2,693	26
	1,026		1,026	27
	5,772		5,772	28
	1,026		1,026	29
	1,984,377		1,984,377	30
	90		90	31
	691		691	32
	19,347		19,347	33
	1,685		1,685	34
6,368,919	**13,003,985**	**0**	**19,372,904**	

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

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	720		720	1
	277		277	2
	47		47	3
	8,031		8,031	4
	90		90	5
	43		43	6
	180		180	7
	626		626	8
	648		648	9
	360		360	10
	12,717		12,717	11
	245		245	12
	1,440		1,440	13
	1,947		1,947	14
	61		61	15
	1,080		1,080	16
	241		241	17
	19,046		19,046	18
	27,371		27,371	19
	35,336		35,336	20
	94,653		94,653	21
	126,998		126,998	22
	33,363		33,363	23
	103,302		103,302	24
	12,952		12,952	25
	144		144	26
	105,610		105,610	27
	22,232		22,232	28
	3,240		3,240	29
	554		554	30
	10,355		10,355	31
	674		674	32
	500		500	33
	345		345	34
6,368,919	**13,003,985**	**0**	**19,372,904**	

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

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	1,444		1,444	1
	4,621		4,621	2
	4,679		4,679	3
	961		961	4
	68		68	5
	3,444		3,444	6
	122		122	7
	366		366	8
	1,464		1,464	9
	122		122	10
	32,139		32,139	11
	5,200		5,200	12
	2,381		2,381	13
	2,503		2,503	14
	137		137	15
	1,942		1,942	16
	244		244	17
	234		234	18
	3,188		3,188	19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
6,368,919	**13,003,985**	**0**	**19,372,904**	

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

5, Open Access Transmission Tariff, Volume 5, first revision

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

The network service agreement between Idaho Power and the Bonneville Power Administration for the Oregon Trail Electric Cooperative expires September 30, 2028. The billing demand for network service is the customer's demand at the time of Idaho Power Company transmission system peak and varies by month.

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

The network service agreement between Idaho Power and the Bonneville Power Administration for the USBR expires December 31, 2014. The billing demand for network service is the customer's demand at the time of Idaho Power Company transmission system peak and varies by month.

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

The network service agreement between Idaho Power and the Bonneville Power Administration for Raft River expired September 30, 2011. The billing demand for network service is the customer's demand at the time of Idaho Power Company transmission system peak and varies by month.

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

The network service agreement between Idaho Power and the Bonneville Power Administration for the Priority Firm Customers expires September 20, 2028. The billing demand for network service is the customer's demand at the time of Idaho Power Company transmission system peak and varies by month.

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

Legacy, contract prior to the Open Access Transmission Tariff

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

The contract between Idaho Power and the Milner Irrigation District expires December 31, 2012.

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

The agreement between Idaho Power and the City of Seattle expires December 31, 2017. City of Seattle has sold this transmission service request to Cargill and Cargill is now responsible for payment.

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

The contract between Idaho Power and PacifiCorp - Imnaha expires on March 31, 2016. The billing demand for network service is the customer's demand at the time of Idaho Power Company transmission system peak and varies by month.

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

Legacy, contract prior to the Open Access Transmission Tariff

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

The agreement between Idaho Power and the United States Department of the Interior, Bureau of Indian Affairs is subject to termination upon 90 days written notice by the Bureau.

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

Legacy, contract prior to the Open Access Transmission Tariff

Schedule Page: 328.6 Line No.: 5 Column: h

Legacy agreement providing OATT-like service, but billed under 454 Facilities revenue

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Avista Corp-WWP Div	NF	21,503	21,503		138,336		138,336
2	Avista Corp-WWP Div	SFP	274,437	274,437		1,473,302		1,473,302
3	Avista Corp-WWP Div	OS					-36,582	-36,582
4	Bonneville Power Admin	OS					447	447
5	Bonneville Power Admin	NF	1,700	1,700		8,011		8,011
6	Bonneville Power Admin	LFP	286,453	286,453	1,195,392			1,195,392
7	Bonneville Power Admin	LFP			30,404			30,404
8	Bonneville Power Admin	SFP				330		330
9	Cargill Power Markets	SFP	4	4		144		144
10	Northwestern Energy	LFP	20,710	20,710	199,600			199,600
11	NorthWesern Energy	SFP	45,995	45,995		818,047		818,047
12	NorthWestern Energy	OS					-205,566	-205,566
13	PacifiCorp Inc.	LFP	8,720	8,720		759,375		759,375
14	PacifiCorp Inc.	NF	34,690	34,690		194,002		194,002
15	PacifiCorp Inc.	OS					-21,949	-21,949
16	PacifiCorp Inc.	SFP	46,666	46,666		649,815		649,815
	TOTAL		1,287,651	1,287,651	1,425,396	5,499,661	-462,953	6,462,104

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	PacifiCorp Inc.	OS					-75,143	-75,143
2	Portland General Ele Co	SFP	361,028	361,028		911,685		911,685
3	Powerex Corp.	OS					-124,160	-124,160
4	Puget Sound Energy, Inc	SFP	600	600		750		750
5	Seattle City Light	SFP	182,876	182,876		527,869		527,869
6	Sierra Pacific Power Co	NF	2,269	2,269		17,995		17,995
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		1,287,651	1,287,651	1,425,396	5,499,661	-462,953	6,462,104

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

Schedule Page: 332 Line No.: 4 Column: a
Reserves Provided

Schedule Page: 332 Line No.: 6 Column: b
Contract Expiration Date 09/30/2016

Schedule Page: 332 Line No.: 7 Column: b
Contract Expiration Date 07/16/2011

Schedule Page: 332 Line No.: 10 Column: b
Contract can be terminated at anytime, with 30 days prior notice.

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

Schedule Page: 332 Line No.: 13 Column: b
Contract Expiration Date 05/31/2014

Schedule Page: 332 Line No.: 15 Column: a
Unreserved Usage Distribution

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

Schedule Page: 332.1 Line No.: 2 Column: a
Resale Transmission

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	405,549
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	268,796
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	1,071,130
6	Richard Dahl	81,340
7	Christine King	69,097
8	Gary Michael	129,360
9	Richard Reiten	58,974
10	Joan Smith	75,162
11	Jan Packwood	54,390
12	Judith Johansen	70,719
13	Thomas Wilford	66,240
14	Robert Tintsman	71,520
15	Stephen Allred	67,757
16		
17	Chamber of Commerce & Other Civic Organizations	104,397
18		
19	Associated Taxpayers of Idaho	22,000
20	Corporate Executive Board	46,750
21	Idaho Association of Commerce & Industry	14,000
22	Idaho Association of Counties	1,000
23	Idaho Mining Association	6,000
24	Idaho Technology Council	10,000
25	National Association of Directors	4,950
26	Northwest Power Pool	91,722
27	Pacific Northwest Utilities	2,000
28	Western Electricity Coordinating Council	828,246
29	Western Energy Institute	26,095
30	Wyoming Taxpayers Association	1,590
31	Misc Memberships under $1,000 (3)	900
32		
33	Misc General Management	
34	Moody's Analytics Inc	28,832
35	New York Stock Exchange	52,067
36	Port Of Morrow	5,475
37	Pr Newswire	14,063
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	3,750,121

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

Recipient	Purpose	Amount
American Stock Transfer & Trust	Transfer & Fees	$ 57,412
Bank Of New York	Port of Morrow	6,593
Broadbridge Financial Solutions	Proxy & Bulletin	49,858
Deutsche Bank	Broker Fees	34,952
E Source	Mgmt Services	23,340
Stock Based Compensation	Stock Expense	432,000
Thomson Financial	Analyst Service	104,855
Wells Fargo	Transfer & fees	125,464
Rate Related Amortization	Misc Expense	230,655
Business Plus	Misc Expense	6,000

Total		$1,071,130
		==========

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			6,764,513		6,764,513
2	Steam Production Plant	18,914,566				18,914,566
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	15,504,618				15,504,618
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	4,926,750				4,926,750
7	Transmission Plant	17,667,549				17,667,549
8	Distribution Plant	43,735,020				43,735,020
9	Regional Transmission and Market Operation					
10	General Plant	12,549,538				12,549,538
11	Common Plant-Electric	-296,299				-296,299
12	TOTAL	113,001,742		6,764,513		119,766,255

B. Basis for Amortization Charges

Account 404 - Basis used to compute charges:

	Balance to be Amortized 1/1/2011	2011 Amortization	Balance to be Amortized 12/31/2011	Remaining months of Amort 12/31/11
(1)	24,000	12,000	12,000	12
(2)	12,521,781	545,446	11,976,335	-
(3)	17,132,308	5,911,223	18,068,415	-
(4)	4,899,594	287,899	4,611,695	204
(5)	227,990	7,945	225,899	336
Total	34,805,673	6,764,513	34,894,344	

(1) Shoshone-Bannock Tribe License & Use Agreement (Termination date December 31, 2023).
(2) Middle Snake Relicensing Costs (Amortized over a 30 year license period).
(3) Computer Software packages (Amortized over a 60 month period from date of purchase).
(4) Shoshone-Bannock Right of Way (Termination date December 31, 2028).
(5) Boardman Retrofit Tech Analysis (Termination date December 31,2040)

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	310.20	633	75.00		4.16	R4.0	21.80
13	311.00	143,759	100.00	-10.00	1.54	S1.0	23.30
14	312.10	81,207	60.00	-7.00	1.68	R3.0	22.60
15	312.20	484,069	70.00	-5.00	2.17	R1.5	22.30
16	312.30	4,208	25.00	20.00	2.57	R3.0	12.20
17	314.00	150,651	50.00	-5.00	2.50	S0.5	20.30
18	315.00	60,126	65.00	-7.00	6.24	S1.5	22.20
19	316.00	13,265	50.00	-5.00	5.93	R0.5	20.80
20	316.10	92	10.00	25.00	8.13	L2.5	7.60
21	316.40	241	10.00	25.00	9.52	L2.5	
22	316.50	83	10.00	25.00	5.94	L2.5	8.20
23	316.60	106	19.00	25.00	3.69	S2.0	12.00
24	316.70	80	19.00	25.00	3.88	S2.0	16.70
25	316.80	1,300	16.00	30.00	14.29	S0.0	9.30
26	316.90	14	30.00	25.00	1.99	S1.5	21.10
27	317.00	8,005					
28	Subtotal Steam	947,839					
29	331.00	156,227	100.00	-25.00	2.71	R2.5	32.10
30	332.10	19,461	90.00	-20.00	2.27	S4.0	27.20
31	332.20	227,957	90.00	-20.00	2.22	S4.0	29.80
32	332.30	5,472			2.87	SQUARE	28.60
33	333.00	197,921	80.00	-5.00	1.91	R3.0	33.00
34	334.00	45,854	50.00	-5.00	3.00	R1.5	25.30
35	335.00	18,534	90.00		2.11	R2.0	30.50
36	335.10	60	15.00		1.70	SQUARE	12.30
37	335.20	364	20.00		3.53	SQUARE	10.70
38	335.30	124	5.00		13.89	SQUARE	2.00
39	336.00	8,112	75.00		1.94	R3.0	30.40
40	Subtotal Hydro	680,086					
41	341.00	7,169	35.00		3.02	SQUARE	30.40
42	342.00	4,446	35.00		2.75	SQUARE	32.40
43	343.00	98,952	35.00		2.98	SQUARE	29.70
44	344.00	31,682	35.00		2.54	SQUARE	33.80
45	345.00	25,078	35.00		2.89	SQUARE	28.30
46	346.00	3,138	35.00		2.71	SQUARE	29.50
47	Subtotal Other	170,465					
48	350.20	30,980	65.00		1.51	R3.0	54.20
49	352.00	57,995	60.00	-30.00	1.68	R3.0	47.30
50	353.00	351,925	45.00	-5.00	2.06	R1.0	35.40

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	354.00	147,491	65.00	-25.00	1.96	S3.0	48.60
13	355.00	107,027	55.00	-60.00	2.81	R2.0	36.70
14	356.00	171,802	65.00	-30.00	1.92	R1.5	48.30
15	359.00	413	65.00		0.98	R3.0	23.80
16	Subtotal Transmission	867,633					
17	360.22	683	30.00		3.33	SQUARE	30.00
18	361.00	32,336	65.00	-30.00	1.85	R2.5	52.60
19	362.00	194,190	50.00	-5.00	1.89	R0.5	42.10
20	364.00	228,880	44.00	-50.00	3.29	R1.5	31.50
21	365.00	122,537	47.00	-40.00	2.95	R0.5	35.10
22	366.00	47,989	60.00	-20.00	1.95	R2.0	51.20
23	367.00	196,701	50.00	-15.00	1.97	S0.5	41.10
24	368.00	429,420	37.00	5.00	1.67	R1.0	30.80
25	369.00	57,225	35.00	-40.00	3.09	R2.5	25.60
26	370.00	13,834	20.00		6.95	O1.0	11.90
27	370.10	57,488	15.00		6.76	S3.0	14.40
28	370.30	41,109	3.00		25.67	SQUARE	1.50
29	371.10	27	10.00	-5.00	3.68	S4.0	1.40
30	371.20	2,728	15.00	-5.00	0.63	R2.0	13.90
31	373.20	4,395	25.00	-25.00	4.09	R1.5	13.90
32	374.00	643					
33	Subtotal Distribution	1,430,185					
34	390.11	26,794	100.00	-5.00	2.38	S1.5	33.60
35	390.12	57,632	50.00	-5.00	2.24	L2.0	36.30
36	390.20	559	30.00		2.58	S3.0	20.80
37	391.11	14,611	20.00		4.97	SQUARE	10.30
38	391.20	20,992	5.00		24.37	SQUARE	2.10
39	391.21	4,956	7.00		13.96	L4.0	3.90
40	392.10	611	10.00	25.00	6.23	L2.5	5.90
41	392.30	2,590	8.00	50.00	8.62	S2.5	4.30
42	392.40	18,957	10.00	25.00	3.58	L2.5	7.30
43	392.50	766	10.00	25.00	1.49	L2.5	8.60
44	392.60	28,766	19.00	25.00	3.69	S2.0	12.00
45	392.70	4,923	19.00	25.00	2.39	S2.0	11.90
46	392.90	4,365	30.00	25.00	1.99	S1.5	21.10
47	393.00	1,600	25.00		5.40	SQUARE	9.70
48	394.00	6,055	20.00		4.84	SQUARE	11.70
49	395.00	11,866	20.00		5.39	SQUARE	10.20
50	396.00	10,696	16.00	30.00	6.95	S0.0	7.00

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	397.10	6,052	15.00		6.16	SQUARE	7.70
13	397.20	20,618	15.00		6.99	SQUARE	9.60
14	397.30	3,514	15.00		8.36	SQUARE	6.60
15	397.40	2,530	10.00		8.20	SQUARE	5.60
16	398.00	5,255	15.00		9.57	SQUARE	6.90
17	Subtotal General	254,708					
18	Total Plant	4,350,916					
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44							
45							
46							
47							
48							
49							
50							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

REGULATORY COMMISSION EXPENSES

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

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Federal Energy Regulatory Commission:				
2	Annual admin charges assessed by FERC	3,420,728		3,420,728	
3					
4	Regulatory FERC fees credit		-465,593	-465,593	
5					
6	General Regulatory Expenses and				
7	Various other Dockets		44,334	44,334	
8					
9	Oregon Hydro - Fees Amortization	158,501		158,501	
10					
11	Regulatory Commission Expenses - Idaho				
12	Rate Case - Misc expenses		29,224	29,224	
13					
14	Regulatory Commission Expenses - Oregon				
15	Rate Case - Misc expenses		10,534	10,534	
16					
17	Other - OPUC				
18	AR - 233		51,581	51,581	
19	UM - 1182		16,345	16,345	
20	UM - 1396		20,721	20,721	
21	UM - 1461		16,225	16,225	
22	PURPA		18,671	18,671	
23	General Regulatory		36,618	36,618	
24	Other matters less than $15,000		91,448	91,448	
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	3,579,229	-129,892	3,449,337	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

REGULATORY COMMISSION EXPENSES (Continued)

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

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
Electric	928	3,420,728					2
							3
Electric	928	-465,593					4
							5
							6
Electric	928	44,334					7
							8
Electric	928	158,501					9
							10
							11
Electric	928	29,224					12
							13
							14
Electric	928	10,534					15
							16
							17
Electric	928	51,581					18
Electric	928	16,345					19
Electric	928	20,721					20
Electric	928	16,225					21
Electric	928	18,671					22
Electric	928	36,618					23
Electric	928	91,448					24
							25
							26
							27
							28
							29
							30
							31
							32
							33
							34
							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		3,449,337					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

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

Classifications:

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

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

Line No.	Classification (a)	Description (b)
1	Approximately $4 million of Idaho Power's 2011	
2	energy efficiency spending was related to	
3	research and analysis, education, technology	
4	evaluation and market transformation. Most of	
5	this activity was done in conjuction with the	
6	Northwest Energy Efficiency Alliance (NEEA).	
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

DISTRIBUTION OF SALARIES AND WAGES

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

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	16,828,328		
4	Transmission	6,540,757		
5	Regional Market			
6	Distribution	16,919,375		
7	Customer Accounts	8,747,995		
8	Customer Service and Informational	4,518,214		
9	Sales			
10	Administrative and General	42,450,346		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	96,005,015		
12	Maintenance			
13	Production	6,667,843		
14	Transmission	3,223,742		
15	Regional Market			
16	Distribution	8,693,630		
17	Administrative and General	1,150,256		
18	TOTAL Maintenance (Total of lines 13 thru 17)	19,735,471		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	23,496,171		
21	Transmission (Enter Total of lines 4 and 14)	9,764,499		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	25,613,005		
24	Customer Accounts (Transcribe from line 7)	8,747,995		
25	Customer Service and Informational (Transcribe from line 8)	4,518,214		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	43,600,602		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	115,740,486		115,740,486
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru 47)			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	115,740,486		115,740,486
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	49,828,835		49,828,835
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	49,828,835		49,828,835
72	Plant Removal (By Utility Departments)			
73	Electric Plant			
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)			
77	Other Accounts (Specify, provide details in footnote):			
78	Stores Expense	4,953,227		4,953,227
79	Other Clearing Accounts	3,094,618		3,094,618
80	Other work in progress	2,261,561		2,261,561
81	Paid absences	19,830,321		19,830,321
82	Preliminary survey and investigation	37,691		37,691
83	Other Accounts	4,739,655		4,739,655
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	34,917,073		34,917,073
96	TOTAL SALARIES AND WAGES	200,486,394		200,486,394

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM: Idaho Power Company

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	4,771	10	800	3,643	250	703		175	
2	February	4,780	1	800	3,609	218	703		250	
3	March	4,516	8	800	3,368	195	703		250	
4	Total for Quarter 1	14,067			10,620	663	2,109		675	
5	April	4,209	26	800	2,649	174	642		744	
6	May	4,155	5	800	2,630	189	567		769	
7	June	5,222	22	1800	3,802	279	567		574	
8	Total for Quarter 2	13,586			9,081	642	1,776		2,087	
9	July	5,492	22	1800	4,364	302	567		259	
10	August	5,462	25	1800	4,305	302	567		288	
11	September	5,037	8	1700	3,707	269	567		494	
12	Total for Quarter 3	15,991			12,376	873	1,701		1,041	
13	October	4,456	1	1800	3,098	206	567		585	
14	November	4,410	16	800	3,368	199	567		276	
15	December	4,544	15	800	3,371	208	567		398	
16	Total for Quarter 4	13,410			9,837	613	1,701		1,259	
17	Total Year to Date/Year	57,054			41,914	2,791	7,287		5,062	

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	13,734,430
3	Steam	4,820,344			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	38,222
5	Hydro-Conventional	10,936,822			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	3,596,702
7	Other	137,829			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	15,894,995	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
10	Purchases	2,777,898	27	Total Energy Losses	1,226,910
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	18,596,264
12	Received	602,391			
13	Delivered	680,849			
14	Net Exchanges (Line 12 minus line 13)	-78,458			
15	Transmission For Other (Wheeling)				
16	Received	6,094,045			
17	Delivered	6,092,216			
18	Net Transmission for Other (Line 16 minus line 17)	1,829			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	18,596,264			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

MONTHLY PEAKS AND OUTPUT

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

NAME OF SYSTEM: Idaho Power Company

Line No.	Month (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	1,597,182	299,156	2,231	4	8 AM
30	February	1,335,990	227,298	2,261	2	8 AM
31	March	1,428,726	307,278	1,907	8	8 AM
32	April	1,345,151	329,304	1,761	6	8 AM
33	May	1,492,714	389,411	1,746	16	11 AM
34	June	1,776,088	467,350	2,842	28	7 PM
35	July	1,859,037	162,831	2,973	6	8 PM
36	August	1,812,353	219,992	2,887	25	5 PM
37	September	1,649,332	352,808	2,564	7	6 PM
38	October	1,415,974	371,794	1,974	1	6 PM
39	November	1,365,640	237,956	1,933	16	8 AM
40	December	1,518,077	231,524	2,135	8	8 AM
41	TOTAL	18,596,264	3,596,702			

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

Page 329 column I differs from Page 401 by 1,829 MWH, reported for Lucky Peak variation and BPA Energy Imbalance schedules on page 401. The numbers that are shown on pages 328-330 are for account 456 wheeling only. However the numbers on page 401 have to be adjusted for account 447 transmission.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Report data for plant in Service only. 2. Large plants are steam plants with installed capacity (name plate rating) of 25,000 Kw or more. Report in this page gas-turbine and internal combustion plants of 10,000 Kw or more, and nuclear plants. 3. Indicate by a footnote any plant leased or operated as a joint facility. 4. If net peak demand for 60 minutes is not available, give data which is available, specifying period. 5. If any employees attend more than one plant, report on line 11 the approximate average number of employees assignable to each plant. 6. If gas is used and purchased on a therm basis report the Btu content or the gas and the quantity of fuel burned converted to Mct. 7. Quantities of fuel burned (Line 38) and average cost per unit of fuel burned (Line 41) must be consistent with charges to expense accounts 501 and 547 (Line 42) as show on Line 20. 8. If more than one fuel is burned in a plant furnish only the composite heat rate for all fuels burned.

Line No.	Item (a)	Plant Name: *Jim Bridger* (b)			Plant Name: *Boardman* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Semi-Outdoor Boiler			Conventional		
3	Year Originally Constructed	1974			1980		
4	Year Last Unit was Installed	1979			1980		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	770.50			64.20		
6	Net Peak Demand on Plant - MW (60 minutes)	710			60		
7	Plant Hours Connected to Load	8760			6927		
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	3865922000			287766000		
13	Cost of Plant: Land and Land Rights	494358			106610		
14	Structures and Improvements	66616189			13839832		
15	Equipment Costs	456703918			60888268		
16	Asset Retirement Costs	0			0		
17	Total Cost	523814465			74834710		
18	Cost per KW of Installed Capacity (line 17/5) Including	679.8371			1165.6497		
19	Production Expenses: Oper, Supv, & Engr	180745			903348		
20	Fuel	92177415			5683939		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	4331677			83277		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	7067950			594345		
27	Rents	498085			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	46835			2028723		
30	Maintenance of Structures	2251			43886		
31	Maintenance of Boiler (or reactor) Plant	6570615			1064		
32	Maintenance of Electric Plant	3076437			235224		
33	Maintenance of Misc Steam (or Nuclear) Plant	5702564			421392		
34	Total Production Expenses	119654574			9995198		
35	Expenses per Net KWh	0.0310			0.0347		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil		Coal	Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels		Tons	Barrels	
38	Quantity (Units) of Fuel Burned	2161284	10732	0	171802	1170	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	9216	140000	0	8341	138800	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	40.722	150.926	0.000	28.907	132.823	0.000
41	Average Cost of Fuel per Unit Burned	42.137	82.085	0.000	32.042	121.791	0.000
42	Average Cost of Fuel Burned per Million BTU	2.282	13.954	0.000	1.937	20.889	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.024	0.000	0.000	0.020	0.000	0.000
44	Average BTU per KWh Net Generation	10337.000	0.000	0.000	9897.000	0.000	0.000

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Valmy* (d)			Plant Name: *Danskin* (e)			Plant Name: *Bennett Mountain* (f)			Line No.
		Steam			Gas Turbine			Gas Turbine	1
		Outdoor			Conventional			Conventional	2
		1981			2001			2005	3
		1985			2001			2005	4
		283.50			270.90			172.80	5
		262			249			194	6
		8718			720			329	7
		0			261426			164159	8
		0			0			0	9
		0			0			0	10
		0			6			7	11
		666656000			89344000			48459000	12
		1106140			402745			0	13
		63302625			5699334			1458303	14
		277849448			104008915			58385597	15
		0			0			0	16
		342258213			110110994			59843900	17
		1207.2600			406.4636			346.3189	18
		606068			228712			159970	19
		21983600			7535390			4154978	20
		0			0			0	21
		2535456			0			0	22
		0			0			0	23
		0			0			0	24
		2231309			262895			250526	25
		2071969			158311			87970	26
		0			0			0	27
		0			0			0	28
		0			0			0	29
		874472			89921			82402	30
		8779359			22042			37902	31
		3515974			575143			986528	32
		362107			0			0	33
		42960314			8872414			5760276	34
		0.0644			0.0993			0.1189	35
Coal	Oil		Gas			Gas			36
Tons	Barrels		MCF			MCF			37
336503	10231	0	958759	0	0	504442	0	0	38
9959	138778	0	1027	0	0	1027	0	0	39
55.215	142.477	0.000	7.860	0.000	0.000	8.237	0.000	0.000	40
61.006	136.892	0.000	7.860	0.000	0.000	8.237	0.000	0.000	41
3.063	23.486	0.000	7.653	0.000	0.000	8.020	0.000	0.000	42
0.033	0.000	0.000	0.084	0.000	0.000	0.086	0.000	0.000	43
10144.000	0.000	0.000	11021.000	0.000	0.000	10691.000	0.000	0.000	44

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 2736 Plant Name: American Falls (b)	FERC Licensed Project No. 1975 Plant Name: Bliss (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Run-of-River
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Outdoor
3	Year Originally Constructed	1978	1949
4	Year Last Unit was Installed	1978	1950
5	Total installed cap (Gen name plate Rating in MW)	92.30	75.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	108	77
7	Plant Hours Connect to Load	8,694	8,760
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	110	76
10	(b) Under the Most Adverse Oper Conditions	0	1
11	Average Number of Employees	4	4
12	Net Generation, Exclusive of Plant Use - Kwh	586,802,000	513,605,000
13	Cost of Plant		
14	Land and Land Rights	875,318	768,358
15	Structures and Improvements	11,807,207	1,039,561
16	Reservoirs, Dams, and Waterways	4,293,075	8,413,888
17	Equipment Costs	31,659,620	8,393,112
18	Roads, Railroads, and Bridges	839,276	486,477
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	49,474,496	19,101,396
21	Cost per KW of Installed Capacity (line 20 / 5)	536.0184	254.6853
22	Production Expenses		
23	Operation Supervision and Engineering	222,397	782,452
24	Water for Power	1,674,772	699,745
25	Hydraulic Expenses	116,486	780,235
26	Electric Expenses	50,572	45,043
27	Misc Hydraulic Power Generation Expenses	210,138	244,914
28	Rents	-568	-45,035
29	Maintenance Supervision and Engineering	89,270	151,939
30	Maintenance of Structures	211,483	274,177
31	Maintenance of Reservoirs, Dams, and Waterways	7,497	518,836
32	Maintenance of Electric Plant	292,363	86,802
33	Maintenance of Misc Hydraulic Plant	103,363	154,730
34	Total Production Expenses (total 23 thru 33)	2,977,773	3,693,838
35	Expenses per net KWh	0.0051	0.0072

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 1971 Plant Name: Hells Canyon (b)	FERC Licensed Project No. 2726 Plant Name: Malad (c)
1	Kind of Plant (Run-of-River or Storage)	Storage	Run-of-River
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Outdoor
3	Year Originally Constructed	1967	1948
4	Year Last Unit was Installed	1967	1948
5	Total installed cap (Gen name plate Rating in MW)	391.50	21.77
6	Net Peak Demand on Plant-Megawatts (60 minutes)	440	24
7	Plant Hours Connect to Load	8,757	8,760
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	445	25
10	(b) Under the Most Adverse Oper Conditions	137	21
11	Average Number of Employees	5	1
12	Net Generation, Exclusive of Plant Use - Kwh	2,816,349,000	173,042,000
13	Cost of Plant		
14	Land and Land Rights	1,877,301	205,376
15	Structures and Improvements	2,811,400	2,777,503
16	Reservoirs, Dams, and Waterways	52,700,383	6,265,302
17	Equipment Costs	17,216,890	4,292,367
18	Roads, Railroads, and Bridges	819,192	304,683
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	75,425,166	13,845,231
21	Cost per KW of Installed Capacity (line 20 / 5)	192.6569	635.9775
22	Production Expenses		
23	Operation Supervision and Engineering	377,827	214,911
24	Water for Power	327,519	702,291
25	Hydraulic Expenses	525,528	259,355
26	Electric Expenses	212,729	47,858
27	Misc Hydraulic Power Generation Expenses	249,786	115,885
28	Rents	82,999	0
29	Maintenance Supervision and Engineering	269,283	34,863
30	Maintenance of Structures	72,377	12,790
31	Maintenance of Reservoirs, Dams, and Waterways	211,408	8,405
32	Maintenance of Electric Plant	174,027	30,574
33	Maintenance of Misc Hydraulic Plant	374,531	52,676
34	Total Production Expenses (total 23 thru 33)	2,878,014	1,479,608
35	Expenses per net KWh	0.0010	0.0086

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 2777 Plant Name: Upper Salmon (b)	FERC Licensed Project No. 2778 Plant Name: Shoshone Falls (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Run-of-River
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional
3	Year Originally Constructed	1937	1907
4	Year Last Unit was Installed	1947	1921
5	Total installed cap (Gen name plate Rating in MW)	34.50	12.50
6	Net Peak Demand on Plant-Megawatts (60 minutes)	37	14
7	Plant Hours Connect to Load	8,760	8,640
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	39	14
10	(b) Under the Most Adverse Oper Conditions	32	11
11	Average Number of Employees	3	2
12	Net Generation, Exclusive of Plant Use - Kwh	293,884,000	110,438,000
13	Cost of Plant		
14	Land and Land Rights	202,399	313,328
15	Structures and Improvements	2,013,430	1,231,506
16	Reservoirs, Dams, and Waterways	5,569,171	512,402
17	Equipment Costs	7,763,706	4,523,995
18	Roads, Railroads, and Bridges	29,359	51,383
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	15,578,065	6,632,614
21	Cost per KW of Installed Capacity (line 20 / 5)	451.5381	530.6091
22	Production Expenses		
23	Operation Supervision and Engineering	388,900	193,209
24	Water for Power	373,144	169,172
25	Hydraulic Expenses	551,980	127,220
26	Electric Expenses	86,416	38,400
27	Misc Hydraulic Power Generation Expenses	205,221	107,273
28	Rents	0	-315
29	Maintenance Supervision and Engineering	97,699	21,664
30	Maintenance of Structures	115,610	31,721
31	Maintenance of Reservoirs, Dams, and Waterways	254,149	6,789
32	Maintenance of Electric Plant	67,839	46,273
33	Maintenance of Misc Hydraulic Plant	239,825	67,634
34	Total Production Expenses (total 23 thru 33)	2,380,783	809,040
35	Expenses per net KWh	0.0081	0.0073

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

FERC Licensed Project No. 1971 Plant Name: Brownlee (d)	FERC Licensed Project No. 2848 Plant Name: Cascade (e)	FERC Licensed Project No. 1971 Plant Name: Oxbow (f)	Line No.
Storage	Run-of-River	Storage	1
Outdoor	Outdoor	Outdoor	2
1958	1983	1961	3
1980	1984	1961	4
585.40	12.42	190.00	5
680	14	220	6
8,760	8,711	8,760	7
			8
747	15	221	9
220	1	202	10
7	2	6	11
2,924,285,000	50,909,000	1,397,275,000	12
			13
17,382,696	82,142	1,210,187	14
31,438,553	7,364,154	9,963,201	15
67,073,285	3,145,630	30,466,784	16
55,992,367	12,696,273	15,820,683	17
518,444	122,668	565,844	18
0	0	0	19
172,405,345	23,410,867	58,026,699	20
294.5086	1,884.9329	305.4037	21
			22
632,600	204,900	350,884	23
576,341	202,919	298,949	24
901,670	320,137	471,375	25
303,160	131,909	186,903	26
408,009	179,822	273,829	27
304,316	-17	49,901	28
455,958	73,556	236,376	29
197,794	63,144	261,452	30
65,107	483	5,321	31
358,259	63,839	162,548	32
682,115	104,754	247,620	33
4,885,329	1,345,446	2,545,158	34
0.0017	0.0264	0.0018	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

FERC Licensed Project No. 2055 Plant Name: C J Strike (d)	FERC Licensed Project No. 503 Plant Name: Swan Falls (e)	FERC Licensed Project No. 18 Plant Name: Twin Falls (f)	Line No.
Run-of-River	Run-of-River	Run-of-River	1
Outdoor	Conventional	Conventional	2
1952	1910	1935	3
1952	1994	1995	4
82.80	25.00	52.74	5
92	25	51	6
8,760	8,760	8,627	7
			8
91	24	53	9
84	14	50	10
6	4	4	11
657,632,000	157,917,000	394,475,000	12
			13
5,473,876	51,675	255,499	14
9,203,458	25,453,938	10,808,047	15
10,438,597	13,856,887	7,908,870	16
11,937,740	30,331,287	20,759,503	17
248,183	835,946	1,917,603	18
0	0	0	19
37,301,854	70,529,733	41,649,522	20
450.5055	2,821.1893	789.7141	21
			22
870,472	212,122	232,982	23
843,278	174,581	216,977	24
1,171,858	148,772	178,393	25
42,777	34,517	53,462	26
355,585	113,831	148,674	27
-113,298	-31,048	-11,887	28
96,665	61,292	30,047	29
128,592	79,419	38,832	30
115,796	183,048	37,877	31
134,533	22,414	38,864	32
144,740	125,136	79,005	33
3,790,998	1,124,084	1,043,226	34
0.0058	0.0071	0.0026	35

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	65	59	6
0	8,760	8,653	7
			8
0	64	61	9
0	60	1	10
0	7	2	11
0	391,028,000	435,475,000	12
			13
114,367	424,428	138,100	14
26,615,283	2,805,900	10,340,105	15
13,556,785	6,916,532	17,114,934	16
1,288,563	8,069,424	27,665,197	17
99,051	88,693	501,877	18
0	0	0	19
41,674,049	18,304,977	55,760,213	20
0.0000	305.0830	937.9346	21
			22
0	379,189	233,958	23
0	352,498	2,115,819	24
6,376,408	379,465	119,064	25
0	232,553	49,500	26
0	203,217	236,962	27
0	-13,894	-11,941	28
0	73,977	44,160	29
0	156,154	43,701	30
0	8,085	80,612	31
0	119,879	79,594	32
54,282	160,281	74,106	33
6,430,690	2,051,404	3,065,535	34
0.0000	0.0052	0.0070	35

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

American Falls generating capacity is dependent upon water releases controlled by the USBR.

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

Cascade generating capacity is dependent upon water releases controlled by the USBR.

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

Upstream storage in Brownlee Reservoir

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

Upstream storage in Brownlee Reservoir

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	Hydro:					
2	Clear Lakes	1937	2.50	2.3	16,495	1,759,923
3	Thousand Springs	1912	8.80	7.4	17,211	9,322,833
4						
5						
6	Internal Combustion:					
7	Salmon Diesel (1)	1967	5.00	4.2	26	909,259
8						
9						
10						
11	(1) Salmon units are classified as standby.					
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
						1
703,969	123,037		36,555			2
1,059,413	213,644		252,473			3
						4
						5
						6
181,852				Diesel		7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40
						41
						42
						43
						44
						45
						46

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Borah	Midpoint	345.00	500.00	S Tower	85.17		1
2	Boardman	Slatt	500.00	500.00	S Tower	1.79		1
3	Summer lake	Hemingway	500.00	500.00	S Tower	0.40		1
4	Hemingway	Midpoint	500.00	500.00	S Tower	0.37		1
5								
6	Jim Bridger	Goshen	345.00	345.00	S Tower	226.40		1
7	State Line	Midpoint	345.00	345.00	S Tower	76.04		2
8	Kinport	Borah	345.00	345.00	S Tower	27.10		1
9	Midpoint	Borah #1	345.00	345.00	H Wood	79.29		1
10	Midpoint	Borah #2	345.00	345.00	H Wood	77.58		2
11	Adelaide Tap	Adelaide	345.00	345.00	H Wood	2.67		2
12								
13	Quartz	LaGrande	230.00	230.00	H Wood	46.30		1
14	Midpoint	Hunt	230.00	230.00	S Tower	0.70		2
15	Brady	Antelope	230.00	230.00	H Wood	56.29		1
16	Brady	Treasureton	230.00	230.00	H Wood	0.11		1
17	Brady #1 & #2	Kinport	230.00	230.00	S Tower	17.94		2
18	Jim Bridger	Point of Rocks	230.00	230.00	H Wood	1.40		1
19	Brownlee	Ontario	230.00	230.00	S Tower	72.74		1
20	Mora	Bowmont	138.00	230.00	S P Wood	9.91		1
21	Mora	Bowmont	138.00	230.00	H Wood	8.82		1
22	Jim Bridger	Point of Rocks	230.00	230.00	H Wood	2.79		1
23	Caldwell 710	Locust	230.00	230.00	SP Steel	18.59		1
24	Boise Bench	Caldwell	230.00	230.00	S Tower	7.56		1
25	Boise Bench	Caldwell	230.00	230.00	H Wood	33.68		1
26	Boise Bench	Cloverdale	230.00	230.00	S Tower	16.10		2
27	Boardman	Dalreed Sub	230.00	230.00	H Wood	1.68		1
28	Brownlee 714	Oxbow	230.00	230.00	SP Steel	11.06		2
29	Caldwell	Ontario	230.00	230.00	H Wood	29.84		1
30	Caldwell	Ontario	230.00	230.00	S Tower	3.27		1
31	Bennett Mtn PP	Rattlesnake TS	230.00	230.00	SP Steel	4.44		1
32	Borah	Hunt	230.00	230.00	H Steel	68.17		1
33	Danskin	Hubbard	230.00	230.00	H Steel	36.28		1
34	Danskin	Hubbard	230.00	230.00	SP Steel	1.90		1
35	Danskin	Hubbard	230.00	230.00	SP Steel	1.30		2
36					TOTAL	4,759.01	11.02	186

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Danskin	Bennett Mtn	230.00	230.00	SP Steel	5.47		1
2	Hemingway	Bowmont	230.00	230.00	SP Steel	13.02		1
3	Langley Gulch Tap			230.00				
4	Boise Bench	Midpoint #1	230.00	230.00	S Tower	0.87		1
5	Boise Bench	Midpoint #1	230.00	230.00	H Wood	108.23		1
6	Brownlee	Quartz Jct	230.00	230.00	S Tower	1.52		1
7	Brownlee	Quartz Jct	230.00	230.00	H Wood	41.32		1
8	Brownlee	Boise Bench #1 & #2	230.00	230.00	S Tower	99.76		2
9	Oxbow	Brownlee	230.00	230.00	S Tower	10.80		2
10	Boise Bench	Midpoint #2	230.00	230.00	S Tower	3.32		1
11	Boise Bench	Midpoint #2	230.00	230.00	H Wood	102.07		1
12	Oxbow	Pallette Jct	230.00	230.00	S Tower	20.03		2
13	Pallette Jct	Imnaha	230.00	230.00	H Wood	24.43		2
14	Hells Canyon	Palette Jct	230.00	230.00	S Tower	8.16		2
15	Brownlee	Boise Bench	230.00	230.00	S Tower	102.08		2
16	Boise Bench	Midpoint #3	230.00	230.00	H Wood	106.31		1
17	Palette Jct	Enterprise	230.00	230.00	H Wood	29.12		1
18	Borah	Brady #2	230.00	230.00	S Tower	0.41		1
19	Borah	Brady #2	230.00	230.00	H Wood	3.56		1
20	Borah	Brady #1	230.00	230.00	H Wood	3.87		1
21								
22	Goshen	State Line	161.00	161.00	H Wood	90.48		1
23	Don	Goshen	161.00	161.00	S Tower	2.39		2
24	Don	Goshen	161.00	161.00	H Wood	48.43		2
25								
26	American Falls Power Plant	Adelaide	138.00	138.00	H Wood	10.99		2
27	American Falls Power Plant	Adelaide	138.00	138.00	S P Wood	0.12		2
28	Minidoka Loop	Adelaide	138.00	138.00	S Tower	1.12		2
29	Nampa	Caldwell	138.00	138.00	S P Wood	10.75		2
30	Upper Salmon	Mountain Home Jct	138.00	138.00	H Wood	54.29		1
31	Upper Salmon	Cliff	138.00	138.00	H Wood	30.81		1
32	Eastgate	Russet	138.00	138.00	S P Wood	2.08		1
33	Brady	Fremont	138.00	138.00	S Tower	0.98		2
34	Brady	Fremont	138.00	138.00	H Wood	24.32		2
35	Brady	Fremont	138.00	138.00	S P Wood	24.33		2
36					TOTAL	4,759.01	11.02	186

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	King	Lower Malad	138.00	138.00	H Wood	84.51		2
2	Emmett Jct	Payette	138.00	138.00	H Wood	66.46		2
3	Mountain Home AFB Tap		138.00	138.00	H Wood	6.20		1
4	Ontario	Quartz	138.00	138.00	H Wood	73.33		1
5	King	American Falls PP	138.00	138.00	S Tower	1.03		2
6	King	American Falls PP	138.00	138.00	H Wood	141.74		1
7	King	American Falls PP	138.00	138.00	S P Wood	3.71		1
8	Duffin	Clawson	138.00	138.00	H Wood	6.22		1
9	American Falls	Brady Tie	138.00	138.00	H Wood	0.33		1
10	Upper Salmon A-B	King	138.00	138.00	H Wood	5.66		1
11	Upper Salmon B	Wells	138.00	138.00	H Wood	125.59		1
12	King	Wood River	138.00	138.00	H Wood	73.71		1
13	Boise Bench	Grove	138.00	138.00	S P Wood	10.38		2
14	Quartz	John Day	138.00	138.00	H Wood	67.32		1
15	Sinker Creek Tap		138.00	138.00	H Wood	2.80		1
16	Mora	Cloverdale	138.00	138.00	H Wood	2.57		1
17	Mora	Cloverdale	138.00	138.00	S P Wood	22.28		1
18	Mora	Cloverdale	138.00	138.00	S P Steel	0.96		2
19	Stoddard Jct	Stoddard Sub	138.00	138.00	S P Steel	3.80		1
20	Fossil Gulch Tap		138.00	138.00	H Wood	1.95		1
21	Wood River	Midpoint	138.00	138.00	H Wood	53.04		2
22	Wood River	Midpoint	138.00	138.00	S P Wood	16.69		2
23	Oxbow	McCall	138.00	138.00	H Wood	37.16		1
24	Oxbow	McCall	138.00	138.00	S P Wood	2.32		1
25	Lowell Jct	Nampa	138.00	138.00	S P Wood	7.50		2
26	Hunt	Milner	138.00	138.00	S P Wood	19.40		1
27	Strike	Bruneau Bridge	138.00	138.00	H Wood	13.49		1
28	American Falls	Kramer Sub	138.00	138.00	S P Wood	18.40		2
29	Pingree	Haven	138.00	138.00	S P Wood	11.72		1
30	Midpoint	Twin Falls	138.00	138.00	S P Wood	25.13		2
31	Twin Falls	Russett	138.00	138.00	S P Wood	1.71		1
32	Blackfoot	Aiken	46.00	138.00	S P Wood	6.18		2
33	Peterson	Tendoy	69.00	138.00	H Wood	57.21		1
34	Eastgate Tap	Eastgate	138.00	138.00	S P Wood	6.36		1
35	Kimberly Tap	Kimberly	138.00	138.00	S P Steel	1.83		2
36					TOTAL	4,759.01	11.02	186

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Boise Bench	Mora	138.00	138.00	H Wood	13.18		2
2	Bowmont-Caldwell	Simplot Sub	138.00	138.00	S P Wood	0.51		1
3	Gary Lane	Eagle	138.00	138.00	S P Wood	6.53		1
4	Locust Grove	Blackcat Sub	138.00	138.00	S P Steel	10.06	2.98	1
5	Boise Bench	Butler	138.00	138.00	S P Wood	0.14	4.02	1
6	Eagle	Star	138.00	138.00	S P Wood	6.39		1
7	Karcher Sub	Zilog Tap	138.00	138.00	S P Steel	2.08		1
8	Cloverdale - 712	712 - Wye	138.00	138.00	S P Steel	0.40	4.02	1
9	Victory Jct	Victory	138.00	138.00	S P Steel	1.90		1
10	Butler	Wye	138.00	138.00	S P Steel	2.94		1
11	Horseflat	Starkey	138.00	138.00	H Wood	33.86		1
12	Starkey	Mccall	138.00	138.00	S P Steel	2.08		2
13	Starkey	Mccall	138.00	138.00	H Wood	3.80		1
14	Starkey	Mccall	138.00	138.00	S P Steel	1.50		1
15	Starkey	Mccall	138.00	138.00	S P Wood	17.61		1
16	Chestnut	Happy Valley	138.00	138.00	S P Steel	2.80		1
17	Garnet	Ward		138.00				
18	McCall	Lake Fork	138.00	138.00	S P Wood	8.80		1
19	McCall	Lake Fork	138.00	138.00	S Steel	2.90		
20	Caldwell	Willis	138.00	138.00	S P Steel	1.30		1
21	Caldwell	Willis	138.00	138.00	S P Steel	1.59		1
22	Caldwell	Willis	138.00	138.00	S P Wood	0.87		1
23	Valivue Tap		138.00	138.00	S P Steel	0.80		2
24	Kinport	Don #1	138.00	138.00	S Tower	1.24		2
25	Donn	HOKU	138.00	138.00	S P Steel	2.74		1
26	Rockland Jct	Rockland Wind Farm	138.00	138.00	S P Steel	5.31		1
27	HOKU	Alamed	138.00	138.00	S P Steel	0.22		2
28	HOKU	Alamed	138.00	138.00	S P Steel	0.23		2
29	HOKU	Alamed	138.00	138.00	S P Steel	2.85		1
30	Twin Falls PP Tap		138.00	138.00	H Wood	0.82		1
31	American Falls PP	Amercian Falls Trans ST	138.00	138.00	S P Steel	0.37		1
32	Lower Salmon	King Tie	138.00	138.00	H Wood	0.11		1
33	C J Strike	Strike Jct	138.00	138.00	S Tower	4.32		2
34	Strike Jct	Mountain Home Jct	138.00	138.00	H Wood	23.39		1
35	Strike Jct	Bowmont		138.00	H Wood	0.05		1
36					TOTAL	4,759.01	11.02	186

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Strike Jct	Bowmont	138.00	138.00	S Tower	0.36		1
2	Strike Jct	Bowmont	138.00	138.00	H Wood	68.24		1
3	Lucky Peak	Lucky Peak Jct	138.00	138.00	H Wood	4.48		2
4	Bliss	King	138.00	138.00	H Wood	10.47		1
5	Milner Deadend	Milner PP	138.00	138.00	S P Wood	1.31		1
6	Swan Falls Tap		138.00	138.00	H Wood	1.00		1
7								
8								
9								
10	Hines	BPA (Harney)	115.00	115.00	H Wood	3.28		1
11								
12								
13	69 Kv Lines		69.00	69.00	H Wood	166.31		1
14	69 Kv Lines		69.00	69.00	S P Wood	938.98		1
15								
16								
17	46 Kv Lines		46.00	46.00	S P Wood	409.08		1
18								
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	4,759.01	11.02	186

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land	Construction and Other Costs	Total Cost	Operation Expenses	Maintenance Expenses	Rents	Total Expenses	
(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	
1272 ACSR	256,381	21,789,412	22,045,793					1
2X1780 ACSR		446,708	446,708					2
1272 ACSR		835,662	835,662					3
1272 ACSR								4
								5
1272 ACSR	483,309	16,763,326	17,246,635					6
795 ACSR	571,979	11,048,835	11,620,814					7
1272 ACSR	344,220	6,008,061	6,352,281					8
715.5 ACSR	283,143	5,876,940	6,160,083					9
715.5 ACSR	64,851	12,257,047	12,321,898					10
715.5 ACSR	51,448	347,946	399,394					11
								12
795 ACSR	62,218	2,841,222	2,903,440					13
715.5 ACSR	9,145	998,452	1,007,597					14
1272 ACSR	108,301	2,930,700	3,039,001					15
795 ACSR		6,186	6,186					16
715.5 ACSR	18,829	969,871	988,700					17
1272 ACSR	1,190	51,525	52,715					18
2X954 ACSR	1,676,838	20,541,790	22,218,628					19
715.5 ACSR	413,793	2,167,266	2,581,059					20
715.5 ACSR								21
1272 ACSR	1,899	212,523	214,422					22
1590 ACSR	2,138,236	8,775,086	10,913,322					23
1272 ACSR	1,748,214	6,980,587	8,728,801					24
715.5 ACSR								25
1272 ACSR	3,062,812	6,869,820	9,932,632					26
795 AAC		80,895	80,895					27
954 ACSR	34,174	16,039,303	16,073,477					28
2X954 ACSR	224,688	6,285,960	6,510,648					29
1272 ACSR								30
1272 ACSR	81,701	1,666,354	1,748,055					31
1590 ACSR	624,917	22,457,621	23,082,538					32
1590 ACSR		15,210,561	15,210,561					33
1590 ACSR								34
1590 ACSR								35
	31,147,986	426,733,642	457,881,628					36

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)	
1590 ACSR		3,528,033	3,528,033					1
1590 ACSR	1,854,996	9,212,985	11,067,981					2
	896,110		896,110					3
715.5 ACSR	336,186	5,172,731	5,508,917					4
715.5 ACSR								5
795 ACSR	53,068	2,229,410	2,282,478					6
795 ACSR								7
VARIOUS	289,934	8,046,450	8,336,384					8
1272 ACSR	14,810	1,182,550	1,197,360					9
715.5 ACSR	227,825	6,380,708	6,608,533					10
VARIOUS								11
1272 ACSR	92,037	2,097,566	2,189,603					12
1272 ACSR	171,081	1,386,300	1,557,381					13
1272 ACSR	44,687	1,252,130	1,296,817					14
954 ACSR	184,817	5,624,726	5,809,543					15
715.5 ACSR	247,857	5,599,323	5,847,180					16
1272 ACSR	84,014	1,739,212	1,823,226					17
1272 ACSR	3,068	416,606	419,674					18
715.5 ACSR								19
1272 ACSR	10,064	311,349	321,413					20
								21
250 COPPER	16,155	648,382	664,537					22
715.5 ACSR	76,041	1,698,355	1,774,396					23
397.5 ACSR								24
								25
250 COPPER	26,507	262,590	289,097					26
250 COPPER								27
715.5 ACSR	21,326	254,909	276,235					28
795 AAC	608,325	1,779,264	2,387,589					29
795 ACSR	47,687	3,565,872	3,613,559					30
795 ACSR	43,568	913,613	957,181					31
795 AAC	270,823	557,504	828,327					32
VARIOUS	564,932	3,770,086	4,335,018					33
VARIOUS								34
VARIOUS								35
	31,147,986	426,733,642	457,881,628					36

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)	
VARIOUS	76,823	2,316,106	2,392,929					1
VARIOUS	30,918	2,512,162	2,543,080					2
397.5 ACSR	1,955	12,983	14,938					3
VARIOUS	34,428	2,150,955	2,185,383					4
715.5 ACSR	216,919	7,976,117	8,193,036					5
715.5 ACSR								6
715.5 ACSR								7
4\0	4,191	309,857	314,048					8
954 ACSR		96,921	96,921					9
250 COPPER	2,741	93,073	95,814					10
VARIOUS	28,490	2,150,317	2,178,807					11
VARIOUS	173,683	2,834,498	3,008,181					12
VARIOUS	225,602	1,652,772	1,878,374					13
397.5 ACSR	92,173	2,362,416	2,454,589					14
VARIOUS	20	77,199	77,219					15
715.5 ACSR	3,168,369	9,724,534	12,892,903					16
VARIOUS								17
795AAC								18
1272 ACSR								19
250 COPPER	450	199,195	199,645					20
397.5 ACSR	349,712	6,997,913	7,347,625					21
397.5 ACSR								22
397.5 ACSR	109,899	2,306,969	2,416,868					23
397.5 ACSR								24
715.5 ACSR	211,131	1,448,294	1,659,425					25
715.5 ACSR	3,324	1,190,604	1,193,928					26
397.5 ACSR	14,927	587,404	602,331					27
715.5 ACSR	13,734	1,051,324	1,065,058					28
397.5 ACSR	18,223	1,276,855	1,295,078					29
VARIOUS	54,848	2,969,759	3,024,607					30
715.5 ACSR	16,790	206,158	222,948					31
715.5 ACSR	13,616	491,359	504,975					32
397.5 ACSR	395,696	3,449,949	3,845,645					33
715.5 ACSR	343,955	2,136,683	2,480,638					34
795 ACSR								35
	31,147,986	426,733,642	457,881,628					36

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
715.5 ACSR	14,697	637,273	651,970					1
795 AAC		49,642	49,642					2
795 AAC	489,037	1,944,888	2,433,925					3
1272 ACSR	935,725	3,601,861	4,537,586					4
1272 ACSR	34,687	838,605	873,292					5
715.5 ACSR	179,817	2,909,434	3,089,251					6
795 AAC	43,035	435,188	478,223					7
1272 ACSR	140,412	709,148	849,560					8
1272 ACSR								9
795 ACSR	134,471	1,405,436	1,539,907					10
715.5 ACSR	2,473,833	18,432,096	20,905,929					11
715.5 ACSR								12
715.5 ACSR								13
715.5 ACSR								14
715.5 ACSR								15
1272 ACSR	78,579	1,821,921	1,900,500					16
	40,580		40,580					17
715.5 ACSR	331,539	4,682,879	5,014,418					18
								19
1272 ACSR	272,231	2,141,218	2,413,449					20
795 ACSR								21
795 ACSR								22
795 ACSR		351,497	351,497					23
715.5 ACSR	1,174	212,777	213,951					24
1272 ACSR	190	398	588					25
795 ACSR		356,945	356,945					26
1272 ACSR								27
795 ACSR								28
795 ACSR								29
250 COPPER	58	63,805	63,863					30
715.5 ACSR		76,560	76,560					31
397.5 ACSR		4,406	4,406					32
715.5 ACSR	5,566	384,068	389,634					33
397.5 ACSR	4,355	2,220,763	2,225,118					34
715.5 ACSR	86,651	1,866,338	1,952,989					35
	31,147,986	426,733,642	457,881,628					36

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
715.5 ACSR								1
								2
715.5 ACSR	7	279,481	279,488					3
715.5 ACSR	5,620	1,052,343	1,057,963					4
715.5 ACSR	2,814	183,606	186,420					5
397.5 ACSR	12,885	261,511	274,396					6
								7
								8
								9
397.5 ACSR	1,978	63,404	65,382					10
								11
								12
VARIOUS	1,499,275	49,640,986	51,140,261					13
VARIOUS								14
								15
								16
VARIOUS	307,949	13,432,476	13,740,425					17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	31,147,986	426,733,642	457,881,628					36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

TRANSMISSION LINES ADDED DURING YEAR

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

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	Rockland Jct	Tockland Wind Farm	5.31	S Pole	19.50	1	1
2	Kimberly Tap		1.83	S Pole	9.40	2	2
3	Victory Jct	Victory	1.90	S Pole	19.50	1	1
4							
5	Neils Hot Springs	Neils Hot Springs	10.44	W Pole	9.90	1	1
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		19.48		58.30	5	5

TRANSMISSION LINES ADDED DURING YEAR (Continued)

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

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

CONDUCTORS			Voltage KV (Operating)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)	(k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
795	ACSR	TAS	138		240,720	116,225		356,945	1
795	ACSR	TVS-DC-HL	138		642,849	434,937		1,077,786	2
1272	ACSR	TAS	138	52,884	1,072,208	715,589		1,840,681	3
									4
397.5	ACSR	T	69		1,223	1,841		3,064	5
									6
									7
									8
									9
									10
									11
									12
									13
									14
									15
									16
									17
									18
									19
									20
									21
									22
									23
									24
									25
									26
									27
									28
									29
									30
									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
				52,884	1,957,000	1,268,592		3,278,476	44

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Adelaide	transmission	345.00	138.00	13.80
2	Aiken	distribution	46.00	13.00	
3	Alameda	distribution	46.00	13.00	
4	Alameda	distribution	138.00	13.09	
5	American Falls PP - attended	transmission	138.00	13.80	
6	American Falls	transmission	138.00	46.00	12.47
7	Artesian	distribution	46.00	13.00	
8	Bannock Creek	distribution	46.00	13.00	
9	Bennett Mountain Power Plant- attended	transmission	230.00	18.00	
10	Bennett Mountain Power Plant- attended	distribution	18.00	4.16	
11	Bethel Court	distribution	138.00	13.00	
12	Black Cat	distribution	138.00	13.09	
13	Blackfoot	distribution	46.00	13.00	
14	Blackfoot	transmission	161.00	46.00	12.47
15	Blackfoot	distribution	161.00	138.00	12.98
16	Bliss - attended	transmission	138.00	13.80	
17	Blue Gulch	distribution	138.00	35.00	
18	Boise Bench - attended	transmission	230.00	138.00	13.20
19	Boise Bench - attended	distribution	138.00	35.00	
20	Boise Bench - attended	transmission	138.00	69.00	12.98
21	Boise Bench - attended	transmission	230.00	138.00	13.80
22	Boise	distribution	138.00	13.00	
23	Borah	transmission	345.00	230.00	13.80
24	Bowmont	distribution	69.00	46.00	6.90
25	Bowmont	distribution	138.00	35.00	
26	Bowmont	transmission	138.00	69.00	12.98
27	Bowmont	transmission	138.00	69.00	12.47
28	Bowmont	transmission	230.00	138.00	13.80
29	Brady	distribution	46.00	13.00	
30	Brady	transmission	230.00	138.00	13.80
31	Brady	transmission	138.00	46.00	12.47
32	Brady	distribution	69.00	13.00	
33	Brownlee - attended	transmission	230.00	13.80	
34	Bruneau Bridge	distribution	138.00	35.00	
35	Buckhorn	distribution	69.00	35.00	
36	Bucyrus	distribution	46.00	7.20	
37	Buhl	distribution	46.00	13.00	
38	Burley Rural	distribution	69.00	13.00	
39	Butler	distribution	138.00	13.09	
40	Caldwell	distribution	138.00	13.00	

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	Caldwell	distribution	138.00	13.09	
2	Caldwell	transmission	138.00	69.00	12.47
3	Caldwell	transmission	230.00	138.00	12.47
4	Caldwell	distribution	13.00	4.16	
5	Canyon Creek	distribution	138.00	35.00	
6	Canyon Creek	transmission	138.00	69.00	12.98
7	Cascade Power Plant - attended	transmission	69.00	4.60	
8	Cascade	Distribution	69.00	13.10	
9	Chestnut	distribution	138.00	13.00	
10	Clear Lake - attended	transmission	46.00	2.40	
11	Cliff	transmission	138.00	46.00	12.50
12	Cliff	transmission	138.00	46.00	12.95
13	Cloverdale	Distribution	138.00	13.00	
14	Dale	distribution	46.00	13.00	
15	Dale	distribution	69.00	13.00	
16	Dale	distribution	138.00	36.20	
17	Dale	Transmission	138.00	46.00	12.47
18	Danskin- attended	Transmission	230.00	18.00	
19	Danskin- attended	transmission	230.00	138.00	13.80
20	Danskin- attended	distribution	18.00	4.16	
21	Danskin- attended	transmission	138.00	12.00	
22	Don	distribution	138.00	7.60	
23	Don	distribution	138.00	13.20	
24	Don	distribution	138.00	13.00	
25	Don	distribution	14.00		
26	DRAM	distribution	138.00	13.09	
27	DRAM	transmission	230.00	138.00	13.80
28	DRAM	distribution	138.00	12.47	
29	Duffin	distribution	138.00	35.00	
30	Eagle	distribution	138.00	13.09	
31	Eastgate	distribution	138.00		
32	Eastgate	distribution	138.00	13.00	
33	Eckert	distribution	138.00	36.20	
34	Eden	distribution	138.00	36.20	
35	Eden	transmission	138.00	46.00	12.98
36	Elkhorn	distribution	138.00	12.47	
37	Elkhorn	distribution	138.00	13.00	
38	Elmore	distribution	138.00	35.00	
39	Elmore	transmission	138.00	69.00	12.50
40	Emmett	distribution	138.00		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Emmett	Transmission	138.00	69.00	12.47
2	Falls	distribution	46.00	13.00	
3	Filer	distribution	46.00	13.00	
4	Flying H	distribution	69.00	2.40	
5	Fort Hall	distribution	46.00	13.00	
6	Fossil Gulch	distribution	138.00	35.00	
7	Fremont	transmission	138.00	46.00	12.50
8	Gary	distribution	138.00	13.00	
9	Gem	distribution	69.00	13.00	
10	Gem	distribution	69.00		
11	Goodng Rural	distribution	46.00	13.00	
12	Golden Valley	distribution	69.00	13.00	
13	Gowen Substation	distribution	138.00	35.00	
14	Grindstone	distribution	35.00		
15	Grove	distribution	138.00	13.09	
16	Hagerman	distribution	46.00	13.00	
17	Hagerman	distribution	46.00	13.00	32.00
18	Hailey	distribution	138.00	13.00	
19	Happy Valley	distribution	138.00	13.09	
20	Haven	distribution	138.00	35.00	
21	Haven	transmission	138.00	46.00	
22	Hemingway	transmission	500.00	230.00	34.50
23	Hewlett Packard	distribution	138.00	13.00	
24	Hidden Springs	distribution	138.00	13.00	
25	Highland	distribution	138.00	13.00	
26	Hill	distribution	138.00	13.00	
27	Hillsdale	distribution	138.00		
28	Hoku	distribution	138.00	13.80	
29	Homedale	distribution	69.00	13.00	
30	Horse Flat	transmission	230.00	138.00	13.80
31	Horseshoe Bend	distribution	35.00		
32	Horseshoe Bend	distribution	69.00	36.20	
33	Horseshoe Bend	distribution	69.00	25.00	
34	Huston	distribution	69.00	13.00	
35	Hulen	distribution	46.00	13.00	
36	Hunt	transmission	230.00	138.00	13.80
37	Hydra	distribution	138.00	36.20	
38	Island	distribution	69.00	13.00	
39	Jerome	distribution	138.00	13.00	
40	Julion Clawson	distribution	138.00	35.00	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Joplin	distribution	138.00	13.00	
2	Joplin	distribution	138.00	35.00	
3	Karcher	distribution	138.00	13.00	
4	Kenyon	distribution	69.00	13.00	
5	Ketchum	distribution	138.00	13.00	
6	Kimberly	distribution	138.00	13.00	
7	Kinport	transmission	161.00	46.00	13.20
8	Kinport	transmission	230.00	138.00	12.47
9	Kinport	transmission	230.00	138.00	13.80
10	Kinport	transmission	345.00	230.00	13.80
11	Kramer	distribution	138.00	35.00	
12	Kramer	distribution	138.00	36.20	
13	Kuna	distribution	138.00	13.00	
14	Lake Fork	distribution	138.00	36.20	
15	Lake Fork	transmission	138.00	69.00	12.50
16	Lamb	distribution	138.00	13.00	
17	Lansing	distribution	69.00	13.00	
18	Lincoln	distribution	138.00	13.09	
19	Linden	distribution	138.00	13.00	
20	Locust	distribution	138.00	36.20	
21	Locust	transmission	230.00	138.00	13.80
22	Lower Malad - attended	transmission	138.00	7.20	
23	Lower Salmon - attended	transmission	138.00	13.80	
24	Map Rock	distribution	69.00	13.00	
25	McCall	distribution	13.00	13.09	
26	McCall	distribution	138.00	36.20	
27	Meridian	distribution	138.00	13.00	
28	Micron	distribution	138.00	13.09	
29	Micron	distribution	138.00	13.00	
30	Midpoint	transmission	230.00	138.00	13.80
31	Midpoint	transmission	345.00	230.00	13.80
32	Midpoint	transmission	500.00	345.00	
33	Midrose	distribution	138.00	13.09	
34	Milner	transmission	138.00	69.00	12.47
35	Milner	distribution	69.00	46.00	6.90
36	Milner	distribution	138.00	35.00	
37	Milner PP - attended	transmission	138.00	13.80	
38	Moonstone	distribution	138.00	35.00	
39	Mora	distribution	138.00	35.00	
40	Mora	distribution	138.00	36.20	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Moreland	distribution	35.00	13.00	
2	Moreland	distribution	46.00	13.00	
3	Moreland	distribution	46.00	35.00	12.47
4	Mountain Home	distribution	69.00	13.00	
5	Mountain Home Air Force Base	distribution	69.00	13.00	
6	Mountain Home Air Force Base	distribution	138.00	13.00	
7	Nampa	distribution	230.00	138.00	13.80
8	Nampa	distribution	138.00	13.00	
9	New Meadows	distribution	138.00	36.20	
10	New Plymouth	distribution	69.00	13.00	
11	Notch Butte	distribution	138.00	13.09	
12	Orchard	distribution	69.00	36.20	
13	Orchard	distribution	69.00	35.00	12.47
14	Parma	distribution	69.00	13.00	
15	Parma	distribution	69.00	35.00	
16	Paul	distribution	138.00	35.00	
17	Payette	distribution	138.00	13.00	
18	Pingree	transmission	138.00	46.00	12.50
19	Pingree	distribution	138.00	35.00	
20	Pleasant Valley	distribution	138.00	35.00	
21	Pocatello	distribution	46.00	13.00	
22	Poleline	distribution	138.00	13.09	
23	Populus	transmission	345.00		
24	Portneuf	distribution	138.00	35.00	
25	Portneuf	distribution	46.00	35.00	
26	Rockford	distribution	46.00	13.00	
27	Russett	distribution	138.00	13.00	
28	Sailor Creek	distribution	138.00	2.40	
29	Sailor Creek	distribution	138.00	35.00	
30	Salmon	distribution	69.00	13.00	
31	Salmon	distribution	69.00	34.50	12.47
32	Salmon	distribution	69.00		12.47
33	Salmon	transmission	13.00	2.40	
34	Shoshone	distribution	46.00	13.00	
35	Shoshone	distribution	46.00	7.20	
36	Shoshone Falls - attended	transmission	46.00	2.30	
37	Shoshone Falls - attended	transmission	46.00	6.60	
38	Silver	distribution	138.00	35.00	
39	Simplot	distribution	138.00	13.00	
40	Sinker Creek	distribution	138.00	35.00	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Siphon	distribution	138.00	35.00	
2	South Park	distribution	46.00	13.00	
3	Star	distribution	138.00	13.09	
4	Starkey	Transmission	138.00	69.00	12.47
5	State	distribution	69.00	13.00	
6	Stoddard	distribution	138.00	13.00	
7	Strike Power Plant - attended	transmission	138.00	13.80	
8	Sugar	distribution	138.00	35.00	
9	Swan Falls - attended	transmission	138.00	6.90	
10	Taber	distribution	46.00	13.00	
11	Ten Mile	distribution	138.00	13.09	
12	Terry	distribution	138.00	13.09	
13	Thousand Springs - attended	transmission	46.00	7.20	
14	Thousand Springs - attended	transmission	7.00	2.40	
15	Toponis	distribution	138.00	33.00	
16	Twin Falls	distribution	138.00	13.09	
17	Twin Falls	transmission	138.00	46.00	12.98
18	Twin Falls PP - attended	transmission	138.00	7.20	
19	Twin Falls PP - attended	transmission	138.00	13.20	
20	Upper Malad - attended	transmission	45.00	7.20	
21	Upper Salmon- attended	transmission	138.00	7.20	
22	Ustick	distribution	138.00	13.00	
23	Vallivue	distribution	138.00	13.09	
24	Victory	distribution	138.00	13.00	
25	Victory	distribution	138.00	13.09	
26	Ware	distribution	69.00	13.00	
27	Weiser	distribution	69.00	13.00	
28	Weiser	transmission	138.00	69.00	12.47
29	Wilder	distribution	69.00	13.00	
30	Willis	distribution	138.00	13.09	
31	Wye	distribution	138.00	13.00	
32	Zilog	distribution	138.00	13.09	
33					
34					
35	The above are all State of Idaho				
36					
37	Montana:				
38	Peterson	transmission	230.00	69.00	13.20
39					
40	Nevada:				

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Valmy - attended	transmission	345.00	17.40	
2	Valmy - attended	transmission	345.00	22.00	
3	Wells	transmission	138.00	69.00	13.00
4					
5	Oregon:				
6	Boardman - attended	transmission	500.00	24.00	
7	Boardman - attended	transmission	230.00	7.20	
8	Boardman - attended	transmission	24.00	7.20	
9	Cairo	distribution	69.00	13.00	
10	Hells Canyon - attended	transmission	230.00	13.80	
11	Hells Canyon - attended	distribution	69.00	0.50	
12	Hines	transmission	138.00	115.00	12.47
13	Malheur Butte	distribution	69.00	34.50	
14	Nyssa	distribution	69.00	13.00	
15	Ontario	distribution	138.00	13.00	
16	Ontario	transmission	138.00	69.00	12.47
17	Ontario	transmission	230.00	138.00	13.80
18	Ontario	transmission	138.00	69.00	12.98
19	Ontario	transmission	138.00	69.00	13.09
20	Ore-Ida	distribution	69.00	13.00	
21	Oxbow - attended	transmission	138.00	69.00	13.00
22	Oxbow - attended	transmission	230.00	13.80	
23	Oxbow - attended	transmission	230.00	138.00	13.80
24	Quartz	transmission	138.00	69.00	12.50
25	Quartz	transmission	230.00	138.00	12.98
26	Quartz	transmission	138.00	69.00	12.98
27	Vale	distribution	69.00	13.00	
28					
29	Wyoming:				
30	Jim Bridger - attended	transmission	345.00	22.00	
31	Jim Bridger - attended	transmission	345.00	230.00	34.50
32					
33					
34					
35					
36					
37	Transformers-distribution substations under 10,000				
38	KVA 84 unattended.				
39					
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) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
300	2					1
20	2					2
15	1					3
18	1					4
72	1					5
25	1					6
10	1					7
10	1					8
135	1					9
5	1					10
15	1					11
24	1					12
30	2					13
50	3	1				14
80	1					15
69	3					16
15	1					17
254	2					18
42	2					19
75	3					20
240	2					21
67	3					22
450	3	1				23
8	3					24
18	1					25
25	1					26
25	1					27
180	1					28
		5				29
312	3					30
		1				31
		1				32
721	5	1				33
30	2					34
20	1					35
6	1	1				36
20	2					37
12	1					38
48	2					39
15	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)	
24	1					1
75	3					2
240	2					3
		1				4
15	1					5
15	1					6
12	1					7
10	1					8
48	2					9
4	1					10
12	2	1				11
4	1					12
48	2					13
		7				14
		1				15
27	1					16
25	1					17
140	1					18
180	1					19
6	1					20
96	2					21
		1				22
108	6	3				23
26	1	1				24
80	6					25
118	7					26
160	2					27
17	1					28
36	2					29
38	2					30
24	1					31
18	1					32
18	1					33
24	1					34
15	1					35
8	1					36
8	1					37
17	1					38
30	2					39
24	1					40

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
25	1					1
18	2					2
10	1					3
15	2					4
10	1	1				5
15	1					6
50	3	1				7
37	2					8
8	1					9
10	1					10
15	2					11
10	1	1				12
24	1					13
5	2					14
72	3					15
10	1					16
5	1					17
20	1					18
18	1					19
12	1					20
25	1					21
600	3	1				22
20	1					23
8	1					24
18	1					25
39	2					26
24	1					27
72	2					28
22	2					29
100	1					30
5	1					31
12	1					32
5	1					33
10	1					34
10	1					35
300	3					36
48	2					37
12	1					38
40	2					39
30	2					40

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/13/2012	Year/Period of Report End of 2011/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
15	1					1
18	1					2
12	1					3
20	2					4
42	2					5
18	1					6
		7				7
180	1					8
180	1					9
600	3	1				10
12	1					11
18	1					12
15	1					13
18	1					14
15	1					15
18	1					16
12	1					17
10	1					18
33	2					19
48	2					20
360	2					21
16	1					22
70	4					23
10	1					24
12	1					25
18	1					26
36	2					27
24	2					28
24	2					29
120	1					30
720	2					31
750	3	1				32
24	1					33
100	4					34
8	3	1				35
29	2					36
36	1					37
12	1					38
15	1					39
24	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
6	1					1
8	1					2
8	4					3
15	1					4
		1				5
18	1					6
180	1					7
50	3					8
12	1					9
10	1					10
10	1					11
6	1					12
10	3					13
10	1					14
12	1					15
36	2					16
23	3					17
50	3					18
22	2					19
42	2					20
36	2					21
18	1					22
						23
18	1					24
		1				25
14	2					26
18	1					27
15	2					28
15	1					29
10	1	3				30
10	3					31
		2				32
5	2					33
10	1					34
2	3					35
3	1					36
10	1					37
12	1					38
15	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.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
33	2					1
10	1					2
18	1					3
18	1					4
33	2					5
15	1					6
83	3					7
20	2					8
18	1					9
5	1					10
24	1					11
42	3					12
8	1					13
3	1					14
18	1					15
44	2					16
33	2					17
9	1					18
72	1					19
8	1					20
36	4					21
44	2					22
18	1					23
24	1					24
18	1					25
12	1	1				26
20	2					27
25	1					28
10	1					29
18	1					30
56	3					31
24	1					32
						33
						34
						35
						36
						37
30	3	1				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) 04/13/2012	Year/Period of Report End of 2011/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
315	1					1
300	1	1				2
20	3	1				3
						4
						5
685	3	1				6
55	1					7
55	1					8
12	1					9
500	3					10
1	1					11
40	1					12
8	3	1				13
20	2					14
38	2					15
25	1	1				16
240	2					17
50	2					18
		1				19
15	1					20
10	3	1				21
244	2					22
100	1					23
15	1					24
100	3	1				25
15	1					26
10	1					27
						28
						29
1122	2					30
1084	22					31
						32
						33
						34
						35
						36
						37
342						38
						39
						40

Schedule Page: 426.2 Line No.: 22 Column: a

PacifiCorp has a 59% interest in certain high-voltage transmission related and interconnection equipment located at Idaho Power's Hemingway Station.

Schedule Page: 426.4 Line No.: 23 Column: a

Idaho Power has a 20.8% interest in certain high-voltage transmission related and interconnection equipment located at PacifiCorp's Populus station.

Schedule Page: 426.6 Line No.: 1 Column: a

Jointly owned with Sierra Pacific Power Company, d/b/a NV Energy. Idaho Power has a 50% share of ownership.

Schedule Page: 426.6 Line No.: 2 Column: a

Jointly owned with Sierra Pacific Power Company, d/b/a NV Energy. Idaho Power has a 50% share of ownership.

Schedule Page: 426.6 Line No.: 6 Column: a

Jointly owned with Portland General Electric, Power Resources Cooperative and BA Leasing BCS, LLC. Idaho Power has a 10% share of the jointly owned capacity. 100% of the capacity is reported.

Schedule Page: 426.6 Line No.: 7 Column: a

Jointly owned with Portland General Electric, Power Resources Cooperative and BA Leasing BCS, LLC. Idaho Power has a 10% share of the jointly owned capacity. 100% of the capacity is reported.

Schedule Page: 426.6 Line No.: 8 Column: a

Jointly owned with Portland General Electric, Power Resources Cooperative and BA Leasing BCS, LLC. Idaho Power has a 10% share of the jointly owned capacity. 100% of the capacity is reported.

Schedule Page: 426.6 Line No.: 30 Column: a

Jointly owned with PacificCorp. Idaho Power has a 33.3% share of ownership.

Schedule Page: 426.6 Line No.: 31 Column: a

Jointly owned with PacificCorp. Idaho Power has a 33.3% share of ownership.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/13/2012	End of 2011/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

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

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2				
3				
4				
5				
6				
7				
8				
9				
10				
11				
12				
13				
14				
15				
16				
17				
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Managerial Expense	IDACORP, Inc.	417420	457,141
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

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

STATE OF OREGON STATEMENT OF OPERATING INCOME FOR THE YEAR

Line No.	Account (a)	(Ref.) Page No. (b)	ELECTRIC UTILITY Current Year (c)	ELECTRIC UTILITY Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)..	2	$ 51,824,852	$ 45,164,928
3	Operating Expenses			
4	Operation Expenses (401)...	8-11	32,008,304	27,621,885
5	Maintenance Expenses (402)..	8-11	3,723,074	3,475,921
6	Depreciation Expense (403)...	12	4,753,703	5,060,768
7	Amort. & Depl. of Utility Plant (404-405).................................	12	291,413	311,511
8	Amort. of Utility Plant Acq. Adj. (406)......................................	12	(980)	(970)
9	Amort. of Property Losses, Unrecovered Plant and Regulatory Study Costs (407-411)	12	(16,415)	(20,431)
10	Amort. of Conversion Expenses (407)....................................	12		
11	Taxes Other Than Income Taxes (408.1)...............................	13	1,961,968	1,828,503
12	Regulatory Debits/Credits...	14	28,099	21,955
13	Income Taxes - Federal (409.1)..	14	(3,387,983)	(594,442)
14	- Other (409.1)..	15	(71,777)	66,674
15	Provision for Deferred Inc. Taxes (410.1)...............................	16-23	2,338,178	4,112,887
16	(Less) Provision for Deferred Income Taxes - Cr.(411.1).........	16-23	(2,000,764)	(3,994,631)
17	Investment Tax Credit Adj. - Net (411.4)..................................	24	(48,731)	(72,619)
18	(Less) Gains from Disp. of Utility Plant (411.6)........................			
19	Losses from Disp. of Utility Plant (411.7)................................			
20	TOTAL Utility Operating Expenses (Enter lines 4 thru 19)....		39,578,089	37,817,011
21	Net Utility Operating Income (Total of line 2 less 20)............		$ 12,246,762	$ 7,347,917

ELECTRIC OPERATING REVENUES (Account 400) - STATE OF OREGON

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.
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 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.

Line No.	(a)	OPERATING REVENUES: Amount for Current Year (b)	OPERATING REVENUES: Amount for Previous Year (c)	MEGAWATT HOURS SOLD: Amount for Current Year (d)	MEGAWATT HOURS SOLD: Amount for Previous Year (e)	AVG NO OF CUSTOMERS PER MONTH: Number for Current Year (f)	AVG NO OF CUSTOMERS PER MONTH: Number for Previous Year (g)	Line No.
1	Sales of Electricity							1
2	(440) Residential Sales	$ 16,078,442	$ 14,709,598	195,077	189,557	13,350	13,419	2
3	(442) Commercial and Industrial Sales							3
4	Small (or Commercial) (See Instr. 4) (1)	14,227,510	13,454,446	199,655	191,650	5,007	5,008	4
5	Large (or Industrial) (See Instr. 4) (2)	12,031,670	11,864,053	241,329	246,935	7	7	5
6	(444) Public Street and Highway Lighting	128,768	125,805	797	799	21	21	6
7	(445) Other Sales to Public Authorities							7
8	(446) Sales to Railroads and Railways							8
9	(448) Interdepartmental Sales							9
10	TOTAL Sales to Ultimate Consumers	42,466,391*	40,153,902*	636,858 **	628,941	18,385	18,455	10
11	(447) Sales for Resale	4,668,925	3,463,778	167,036	91,230			11
12	TOTAL Sales of Electricity	47,135,316	43,617,680	803,894	720,171	18,385	18,455	12
13	(Less) (449.1) Provision for Rate Refunds	-	(42,849)					13
14	TOTAL Revenue Net of Provision for Refunds	47,135,316	43,574,831					
15	Other Operating Revenues							
16	(450) Forfeited Discounts							
17	(451) Miscellaneous Service Revenues	87,179	77,330					
18	(453) Sales of Water and Water Power							
19	(454) Rent from Electric Property	1,190,569	1,077,782					
20	(455) Interdepartmental Rents							
21	(456) Other Electric Revenues	3,411,789	434,985					
22								
23								
24								
25	TOTAL Other Operating Revenues	4,689,537	1,590,097					
26	TOTAL Electric Operating Revenues	$ 51,824,852	$ 45,164,928					

* Includes $-192,605 unbilled revenues.

** Includes -3,213 MWH relating to unbilled revenues.

(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.

STATE OF OREGON SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the KWH of electricity sold, revenue, average number of customers, average KWH per customer, and average revenue per KWH, excluding data 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 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 (Thousands) (c)	Average Number of Customers (d)	KWH of Sales per Customer (e)	Revenue (cents) per KWH Sold (f)
1	440 - Residential Sales:					
2	1 - Residential	193,835	$ 15,993,160	13,350	14,519	8.25
3	3 - Residential-Mastered Metered					
4	84 - Residential-Net Metering					
5	15 - Dusk to Dawn customer Lighting	200	49,885			24.94
6	Residential - Billed	194,035	16,043,045	13,350	14,534	8.27
7	Residential - Unbilled	1,042	35,397	**1		3.40
8	**Total 440**	195,077	16,078,442	13,350	14,612	8.24
9						
10	442 - Commercial and Industrial Sales:					
11	7 - General Service	17,996	1,659,177	2,441	7,372	9.22
12	9 - General Service	129,784	8,402,653	887	146,249	6.47
13	84 - General Service-Net Metering					
14	15 - Dusk to dawn customer lighting	280	63,382	0		22.64
15	19 - Uniform rate contracts	246,198	12,271,289	7	35,171,143	4.98
16	24 - Irrigation and soil drainage pumping	50,968	4,089,452	1,676	30,411	8.02
17	40 - General Service	11	871	2	5,500	7.92
18	Commercial & Industrial - Billed	445,237	26,486,824	5,014	88,805	5.95
19	Commercial & Industrial - Unbilled	(4,253)	(227,644)	**1		5.35
20	**Total 442**	440,984	26,259,180	5,014	87,956	5.95
21						
22						
23	444 - Public Street and Highway Lighting:					
24	40 - General Service	2	164	1	2,000	8.20
25	41 - Municipal street lighting	780	127,602	14	55,714	16.36
26	42 - Municipal traffic control signal lighting	17	1,360	6.25	2,720	8.00
27	Public Street and Highway lighting billed	799	129,126	21	37,600	16.16
28	Public Street and Highway lighting-unbilled	(2)	(358)	**1		
29	**Total 444**	797	128,768	21	37,506	16.16
30						
31						
32						
33						
34						
35	Total Billed	640,071	42,658,995	18,385	34,814	6.66
36	Total Unbilled Rev. (See Instr. 6)	(3,213)	(192,605)	**1		
37	TOTAL	636,858	42,466,390	18,385	34,814	6.66

Irrigation number does not include inactive irrigation count for the year.

**1 Number of customers unknown.

ALLOCATED SALES FOR RESALE (Account 447) - STATE OF OREGON

1. Report sales during the year to other electric utilities and to cities or other public authorities for distribution to ultimate consumers.

2. Provide in column (a) subheadings and classify sales as to (1) Associated Utilities, (2) Nonassociated Utilities, (3) Municipalities, (4) Cooperatives, and (5) Other Public Authorities. For each sale designate statistical classification in column (b) using the following codes: FP, firm power supplying total system requirements of customer or total requirements at a specific point of delivery; FP(C), firm power supplying total system requirements of customer or total requirements at a specific point of delivery with credit allowed customer for available standby; FP(P), firm power supplementing customer's own generation or other purchases; DP, dump power; O, other. Describe in a footnote the nature of any sales classified as Other Power. Place an "x" in column (c) if sales involves export across a state line. Group together sales coded "x" in column (c) by state (or county) of origin identified in column (e), providing a subtotal for each state (or county) of delivery in columns (L) and (p).

Line No.	Sales To (a)	Stat. Class. (b)	Export Across State Lines (c)	FERC Rate Sch. No. (d)	Point of Delivery (State or County) (e)	Station Owner-Ship (f)	MW or MVa of Demand (Specify which) Contract Demand (g)	Average Monthly Maximum Demand (h)	Annual Maximum Demand (i)
1									
2									
3	Various Utilities								
4									
5									
6									
7									
8									
9									
10									
11									
12									
13									
14									
15									
16									
17									
18									
19									
20									
21									
22									
23									
24									
25									
26									
27									
28									
29									

ALLOCATED SALES FOR RESALE (Account 447) (Continued) - STATE OF OREGON

3. Report separately firm, dump, and other power sold to the same utility.

4. If delivery is made at a substation, indicate ownership in column (f), using the following codes: RS, respondent owned or leased; CS, customer owned or leased.

5. If a fixed number of megawatts of maximum demand is specified in the power contract as a basis of billings to the customer, enter this number in column (g). Base the number of megawatts of maximum demand entered in columns (h) and (i) on actual monthly readings. Furnish these figures whether or not they are used in the determination of demand charges. Show in column (j) type of demand reading (i.e., instantaneous, 15, 30, or 60 minutes integrated).

6. For column (l) enter the number of megawatt hours shown on the bills rendered to the purchasers.
7. Explain in a footnote any amounts entered in column (o), such as fuel or other adjustments.
8. If a contract covers several points of delivery and small amounts of electric energy are delivered at each point, such sales may be grouped.

Type of Demand Reading (j)	Voltage at Which Delivered (k)	Megawatt Hours (l)	REVENUE Demand Charges (m)	Energy (n)	Other Charges (o)	Total (p)	Line No.
							1
							2
				4,668,925		$ 4,668,925	3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
							15
							16
							17
							18
							19
							20
							21
							22
							23
							24
							25
							26
							27
							28
							29

SALES TO RAILROADS AND RAILWAYS AND INTERDEPARTMENTAL SALES (Accounts 446, 448)

1. Report particulars concerning sales included in Accounts 446 and 448.
2. For Sales to Railroads and Railways, Account 446, give name of railroad or railway in addition to other required information. If contract covers several points of delivery and small amounts of electricity are delivered at each point, such sales may be grouped.
3. For Interdepartmental Sales, Account 448, give name of other department and basis of charge to other department in addition to other required information.
4. Designate associated companies.
5. Provide subheading and total for each account.

Line No.	Item (a)	Point of Delivery (b)	Kilowatt-hours (c)	Revenue (d)	Revenue per KWH (e)
1	None				
2					
3					
4					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

RENT FROM ELECTRIC PROPERTY AND INTERDEPARTMENTAL RENTS (Accounts 454, 455)

1. Report particulars concerning rents received included in Accounts 454 and 455.
2. Minor rents may be grouped by classes.
3. If rents are included which were arrived at under an arrangement for apportioning expenses of a joint facility, whereby the amount included in this account represents profit or return on property, depreciation, and taxes, give particulars and the basis of apportionment of such charges to Account 454 or 455.
4. Designate if lessee is an associated company.
5. Provide a subheading and total for each account.

Line No.	Name of Lessee or Department (a)	Description of Property (b)	Amount of Revenue For Year (c)
21	Various	Substation Equipment Rental	$ 452,982
22			
23	"	Transformer Rentals - Dist	728
24			
25	"	Line Rentals	95,742
26			
27	"	Cogeneration	34,454
28			
29	"	Pole Attachments	135,307
30			
31	"	Facilities Charges	441,175
32			
33	"	Other Rentals	30,181
34			
35	"	Miscellaneous	-
36			
37	"		
38	Total Account 454		$ 1,190,569

ALLOCATED SALES OF WATER AND WATER FOR POWER (Account 453) - OREGON

1. Report below the information called for concerning revenues derived during the year from sales to others of water or water power.
2. In column (c) show the name of the power development of the respondent supplying the water or water power sold.
3. Designate associated companies.

Line No.	Name of Purchaser (a)	Purpose for which Water was Used (b)	Power Plant Development (c)	Amount of Revenue for Year (d)
1	None			
2				
3		TOTAL		

MISCELLANEOUS SERVICE REVENUES AND OTHER ELECTRIC REVENUES (Accounts 451, 456)

1. Report particulars concerning miscellaneous service revenues and other electric revenues derived from electric utility operations during year. Report separately in this schedule the total revenues from operation of fish and wildlife and recreation facilities, regardles of whether such facilities are operated by company or by contract concessionaires. Provide a subheading and total for each account. For account 456, list first revenues realized through Research and Development ventures, see account 456.
2. Designate associated companies.
3. Minor items may be grouped by classes.

Line No.	Name of Company and Description of Service	Amount of Revenue for Year (b)
4	Account 451	
5		
6	Miscellaneous Service Revenues	$ 87,179
7		
8	Account 456	
9		
10	Transmission for Others - Network	$ 273,914
11	Transmission - Point-to-Point and Other	560,622
12	Alternate Service Charge	-
13	Photovoltaic Station Service	93
14	DSM Rider Funds	2,566,890
15	Sierra Pacific Usage Charge	6,860
16	Antelope	3,191
17	Miscellaneous	219
18		
19		
20	Total Account 456	$ 3,411,789
21		
22		
23		

ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES - OREGON

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	$ 72,882	$ 80,583
5	(501) Fuel	5,507,237	6,763,190
6	(502) Steam Expenses	319,392	337,755
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	102,535	98,515
10	(506) Miscellaneous Steam Power Expenses	419,757	418,059
11	(507) Rents	21,478	9,785
12	(509) Allowances		
13	TOTAL Operation (Enter Total of lines 4 thru 12)	6,443,282	7,707,888
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	89,501	97,830
16	(511) Maintenance of Structures	39,698	13,201
17	(512) Maintenance of Boiler Plant	705,427	739,619
18	(513) Maintenance of Electric Plant	313,750	180,225
19	(514) Maintenance of Miscellaneous Steam Plant	279,689	160,137
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	1,428,066	1,191,011
21	TOTAL Power Production Expenses-Steam Power (Enter Total of lines 13 and 20)	7,871,348	8,898,899
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	233,121	230,015
45	(536) Water for Power	378,267	312,454
46	(537) Hydraulic Expenses	539,589	455,354
47	(538) Electric Expenses	70,763	68,265
48	(539) Miscellaneous Hydraulic Power Generation Expenses	132,863	123,557
49	(540) Rents	9,022	17,342
50	TOTAL Operation (Enter Total of lines 44 thru 49)	1,363,624	1,206,987

ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued) - OREGON

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	$ 76,052	$ 83,967
54	(542) Maintenance of Structures	74,293	49,310
55	(543) Maintenance of Reservoirs, Dams, and Waterways	67,411	58,379
56	(544) Maintenance of Electric Plant	78,859	139,590
57	(545) Maintenance of Miscellaneous Hydraulic Plant	117,260	129,264
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	413,875	460,511
59	TOTAL Power Production Expenses-Hydraulic Power (Enter Total of lines 50 and 58)	1,777,499	1,667,498
61	Operation		
62	(546) Operation Supervision and Engineering	35,368	14,013
63	(547) Fuel	537,509	586,709
64	(548) Generation Expenses	32,798	19,554
65	(549) Miscellaneous Other Power Generation Expenses	33,606	19,209
66	(550) Rents	-	-
67	TOTAL Operation (Enter Total of lines 62 thru 66)	639,280	639,485
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	-	2
70	(552) Maintenance of Structures	7,741	7,768
71	(553) Maintenance of Generating and Electric Plant	5,126	5,158
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	80,265	45,966
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	93,132	58,893
74	TOTAL Power Production Expenses-Other Power (Enter Total of lines 67 and 73)	732,412	698,378
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	7,200,851	6,335,926
77	(556) System Control and Load Dispatching	53	7
78	(557) Other Expenses	4,007,949	1,901,645
79	TOTAL Other Power Supply Expenses (Enter Total of lines 76 thru 78)	11,208,853	8,237,578
80	TOTAL Power Production Expenses (Enter Total of lines 21, 41, 59, 74, and 79)	21,590,112	19,502,353
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	143,800	114,804
84	(561) Load Dispatching	125,345	126,005
85	(562) Station Expenses	97,328	76,517
86	(563) Overhead Line Expenses	32,271	25,262
87	(564) Underground Line Expenses		
88	(565) Transmission of Electricity by Others	296,953	272,435
89	(566) Miscellaneous Transmission Expenses	13,308	12,920
90	(567) Rents	141,930	60,190
91	TOTAL Operation (Enter Total of lines 83 thru 90)	850,934	688,135
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	9,536	20,726
94	(569) Maintenance of Structures	18,460	16,014
95	(570) Maintenance of Station Equipment	128,578	132,752
96	(571) Maintenance of Overhead Lines	158,975	106,450
97	(572) Maintenance of Underground Lines		
98	(573) Maintenance of Miscellaneous Transmission Plant	237	(2)
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	315,785	275,941
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	1,166,719	964,076
102	Operation		
103	(580) Operation Supervision and Engineering	160,562	219,320

ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued) - OREGON			
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	$ 146,197	$ 139,079
106	(582) Station Expenses	41,182	51,322
107	(583) Overhead Line Expenses	221,227	210,841
108	(584) Underground Line Expenses	29,040	29,547
109	(585) Street Lighting and Signal System Expenses	5,920	3,888
110	(586) Meter Expenses	95,621	153,851
111	(587) Customer Installations Expenses	89,143	128,876
112	(588) Miscellaneous Distribution Expenses	235,482	295,556
113	(589) Rents	35,612	26,034
114	TOTAL Operation (Enter Total of lines 103 thru 113)	1,059,986	1,258,314
115	Maintenance		
116	(590) Maintenance Supervision and Engineering	17,245	21,970
117	(591) Maintenance of Structures	210	(462)
118	(592) Maintenance of Station Equipment	111,542	151,608
119	(593) Maintenance of Overhead Lines	1,055,134	995,111
120	(594) Maintenance of Underground Lines	16,764	16,541
121	(595) Maintenance of Line Transformers	18,215	40,762
122	(596) Maintenance of Street Lighting and Signal Systems	26,871	28,743
123	(597) Maintenance of Meters	10,939	25,528
124	(598) Maintenance of Miscellaneous Distribution Plant	20,614	11,654
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	1,277,534	1,291,456
126	TOTAL Distribution Expenses (Enter Total of lines 114 and 125)	2,337,520	2,549,770
127	4. CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision	16,174	18,365
130	(902) Meter Reading Expenses	104,650	269,406
131	(903) Customer Records and Collection Expenses	479,723	486,124
132	(904) Uncollectible Accounts	253,623	158,891
133	(905) Miscellaneous Customer Accounts Expenses	11	14
134	TOTAL Customer Accounts Expenses (Enter Total of lines 129 thru 133)	854,180	932,801
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision	33,549	13,104
138	(908) Customer Assistance Expenses	2,796,584	1,930,080
139	(909) Informational and Instructional Expenses	3,066	1,179
140	(910) Miscellaneous Customer Service and Informational Expenses	33,749	32,094
141	TOTAL Cust. Service and Informational Expenses (Enter Total of lines 137 thru 140)	2,866,947	1,976,457
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	3,063,253	2,931,640
152	(921) Office Supplies and Expenses	718,235	626,939
153	(922) Administrative Expenses Transferred-Credit	(1,186,640)	(1,280,204)

Line No.	ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued) - OREGON If the amount for previous year is not derived from previously reported figures, explain in footnotes. Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
154	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
155	(923) Outside Services Employed	$ 224,731	$ 332,057
156	(924) Property Insurance	135,642	140,564
157	(925) Injuries and Damages	264,890	261,035
158	(926) Employee Pensions and Benefits	2,901,785	1,382,965
159	(927) Franchise Requirements	-	-
160	(928) Regulatory Commission Expenses	402,734	383,202
161	(929) Duplicate Charges-Cr		
162	(930.1) General Advertising Expenses	25,190	19,247
163	(930.2) Miscellaneous General Expenses	171,091	176,196
164	(931) Rents	306	597
165	TOTAL Operation (Enter Total of lines 151 thru 164)	6,721,216	4,974,240
166	Maintenance		
167	(935) Maintenance of General Plant	194,683	198,109
168	TOTAL Administrative and General Expenses (Enter Total of lines 165 thru 167)	6,915,899	5,172,349
169	TOTAL Electric Operation and Maintenance Expenses (Enter Total of lines 80, 100, 126, 134, 141, 148, and 168)	$ 35,731,378	$ 31,097,806

Line No.	SUMMARY OF ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES - OREGON Functional Classification (a)	Operation (b)	Maintenance (c)	Total (d)
170	Power Production Expenses			
171	Electric Generation:			
172	Steam power	$ 6,443,282	$ 1,428,066	$ 7,871,348
173	Nuclear power			
174	Hydraulic - Conventional	1,363,624	413,875	1,777,499
175	Hydraulic - Pumped Storage			
176	Other power	639,280	93,132	732,412
	Other Power Supply Expenses	11,208,853	-	11,208,853
177	Total Power Production Expenses	19,655,040	1,935,073	21,590,112
178	Transmission Expenses	850,934	315,785	1,166,719
179	Distribution Expenses	1,059,986	1,277,534	2,337,520
180	Customer Accounts Expenses	854,180	-	854,180
181	Customer Service and Informational Expenses	2,866,947	-	2,866,947
182	Sales Expenses	-	-	-
183	Administrative and General Expenses	6,721,216	194,683	6,915,899
184	Total Electric Operation and Maintenance Expenses	$ 32,008,304	$ 3,723,074	$ 35,731,378

ALLOCATED DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405) - OREGON
(Except amortization of acquistion adjustments)

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Amortization of Limited-Term Electric Plant (Account 404) (c)	Amortization of Other Electric Plant (Acct. 405) (d)	Total (e)
1	Intangible Plant	$ -	$ 291,413		$ 291,413
2	Steam Production Plant	815,626	-		815,626
3	Nuclear Production Plant				-
4	Hydraulic Production Plant - Conventional	668,584	-		668,584
5	Hydraulic Production Plant - Pumped Storage				
6	Other Production Plant	212,449	-		212,449
7	Transmission Plant	763,854	-		763,854
8	Distribution Plant	1,765,381	-		1,765,381
9	General Plant	540,274	-		540,274
10	Depreciation on Disallowed Costs	(12,465)	-		(12,465)
11	TOTAL	$ 4,753,703	$ 291,413		$ 5,045,115

B. OTHER AMORTIZATION

Describe briefly the nature of each transaction giving rise to amortization included in Account 406, Amortization of Utility Plant Acquisition Adjustments, or Account 407, Amortization of Property Losses. Provide the requested information for each transaction, as well as providing a total for each account.

Nature of Transaction	OPUC Number	Amortization Period	Amount
Account 406			
Amortization of Electric Plant Acquisition Adjustment - Prairie Power			$ (980)
Account 411			
411.6			$ 750
411.7			-
411.8			(17,165)
			$ (17,394)

ALLOCATED TAXES, OTHER THAN INCOME TAXES (ACCOUNT 408.1) - OREGON

	KIND OF TAX	Amount
1	Federal Taxes:	
2	FICA	$ 589,836
3	FUTA	5,508
4	Less: Payroll Deduction and Loading	(627,348)
5	State Taxes:	
6	Ad Valorem	998,068
7	Licenses - Hydro Projects	201
8	Regulatory Commission Fees	148,358
9	Franchise Taxes	703,382
10	State Unemployment Taxes	32,004
11	Hydro Generation KWH Tax	111,959
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23	TOTAL (Must agree with page 1, line 11.)	$ 1,961,968

CALCULATION OF CURRENT FEDERAL INCOME TAX EXPENSE - Account 409.1

1. Report amounts used to derive current Federal income tax expense, Account 409.1, for the reporting period. If amounts are shown in thousands, show (000) in the heading for column (b).

2. Show amounts increasing taxable income as positive values and amounts decreasing taxable income as negative.

3. Current tax expense on this schedule must match the amount reported on page 1, line 12 of this report. Separately identify adjustments arising from revisions of prior year accruals.

4. Minor amounts of other additions (subtractions) may be grouped.

Line No.	Particulars (Details) (a)	Amount (b)
1	Electric Operating Revenues	$ 51,824,852
2	Operations and Maintenance Expenses	35,731,378
3	Taxes Other Than Income	1,961,968
4	Regulatory Debits/Credits	28,099
5	State Income (Excise) Tax	474,688
6	Interest	3,654,329
7	Federal Income Tax Depreciation	4,753,703
8	Other Line Items to Derive Taxable Income	
9	Amortization of Limited-Term Plant	274,018
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24	Federal Tax Net Income	$ 4,946,669
25		
26		
27	Show Computation of Tax:	
28		
29	Federal Income Tax @ 35%	$ 1,731,334
30	FIN 48 Adjustment	(4,521,051)
31	Prior Years' Tax Adjustment	(135,126)
32	Total Federal Income Tax Before Other Adjustments	(2,924,843)
33		
34	Other Tax Adjustments	
35	Allowance for AFUDC	$ 1,671,114
36	Income Tax Adjustments	(2,994,370)
37	Federal Tax on Other Tax Adj @ 35%	(463,139)
38		
39	Total Federal Income Tax	$ (3,387,983)

CALCULATION OF CURRENT STATE INCOME (EXCISE) TAX EXPENSE - Account 409.1

1. Report amounts used to derive current state income (excise) tax expense, Account 409.1, for the reporting period. If amounts are shown in thousands, show (000) in the heading for column (b).

2. Show amounts increasing taxable income as positive values and amounts decreasing taxable income as negative.

3. Current tax expense on this schedule must match the amount reported on page 1, line 13 of this report. Separately identify adjustments arising from revisions of prior year accruals.

4. Minor amounts of other additions (subtractions) may be grouped.

Line No.	Particulars (Details) (a)	Amount (b)
1	Electric Operating Revenues	$ 51,824,852
2	Operations and Maintenance Expenses	35,731,378
3	Taxes Other Than Income	1,961,968
4	Regulatory Debits/Credits	28,099
5	Interest	3,654,329
6	State Income (Excise) Tax Depreciation	4,753,703
7		
8	Other Line Items to Derive Taxable Income	
9	Amortization of Limited-Term Plant	274,018
10	Income Tax Adjustments	3,545,762
11	Allowance for AFUDC	(1,671,114)
12	IERCO Taxable Income	(214,657)
13		
14	State Tax Net Income	$ 3,761,366
15		
16		
17		
18		
19	Show Computation of Tax:	
20		
21	State Taxes	474,688
22	Add: FIN 48 Adjustment	(548,993)
23	Prior Period Adjustment	2,528
24		
25		
26	Total Oregon State Tax	$ (71,777)

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. In the space provided:
   (a) identfy, by amount and classification, significant items for which deferred taxes are being provided.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited (Account 410.1) (c)	Amounts Credited (Account 411.1) (d)
1	Electric			
2	Emission Allowances	$	$ -	$ (28,142)
3	Advances for Construction		107,412	0
4	Other Operating (See Note 1)		563,677	(2,785,838)
5				
6	Non-Operating			
7				
8				
9	Total Electric	$	$ 671,089	$ (2,813,981)
10	Gas	$	$	$
11				
12				
13	Other			
14	Total Gas	$	$	$
15	Other Non-Electric	$	$	$
16	Total (Account 190)	$	$ 671,089	$ (2,813,981)
17	Classification of TOTALS			
18	Federal Income Tax	$	$	$
19	State Income Tax	$	$	$
20	Local Income Tax	$	$	$

Note 1:			
Deferred GBC		0	0
Rate Case Disallowance		7,956	0
Other Employees's Long-term Deferred Compensation		54,418	(26,178)
SFAS 112 - Post Retirement Benefits		18,367	0
Non-VEBA Pension and Benefits		8,229	0
FAS 123R - Stock Based Compensation		55,016	(70,548)
Provision for Rate Refunds		0	0
Revenue Sharing		391,122	(976,702)
Delivery Accruals		0	(844)
Bonus Deferral		0	(28)
FIN 48 Interest		5,145	0
Deferred Idaho ITC		8,407	(83,348)
VEBA - Post Retiree Benefits		4,956	(105,346)
Pension Expense		0	(1,226,941)
FERC Credit OFA		10,061	0
AFUDC Hells Canyon Relicensing		0	(257,900)
Oregon Pension Expense		0	(38,004)
Total	$	$ 563,677	$ (2,785,838)

ACCUMULATED DEFERRED INCOME TAXES (Account 190) (Continued)

(b) indicate insignificant amounts under OTHER.
3. Beginning balance may be omitted if not readily available. Report electric utility deferred taxes only.
4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited (Account 410.2) (e)	Amounts Credited (Account 411.2) (f)	Debits Acct. No. (g)	Debits Amount (h)	Credits Acct. No. (i)	Credits Amount (j)	(k)	
							1
$	$		$		$	$	2
							3
							4
							5
16,532	(71,328)						6
							7
							8
$ 16,532	$ (71,328)		$		$	$	9
$	$		$		$	$	10
							11
							12
							13
$	$		$		$	$	14
$ -			$		$	$	15
$ 16,532	$ (71,328)		$		$	$	16
							17
$	$		$		$	$	18
$	$		$		$	$	19
$	$		$		$	$	20
$ -	$ -						

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

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amortizable property.

2. In the space provided furnish explanations, including the following in columnar order:
   (a) State each certification number with a brief description of property.
   (b) Total and amortizable cost of such property.
   (c) Date amortization for tax purposes commenced.

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

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

(d) "Normal" depreciation rate used in computing the deferred tax.
(e) Tax rate used to originally defer amounts and the tax rate used during the current year to amortize previous deferrals.

3. Beginning balance may be omitted if not readily available. Report electric utility deferred taxes only.

4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited (Account 410.2) (e)	Amounts Credited (Account 411.2) (f)	Acct. No. (g)	Amount (h)	Acct. No. (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
							15
							16
$ -	$ -						17
							18
							19
							20
							21

ACCUMULATED DEFERRED INCOME TAXES-OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to property not subject to accelerated amortization.

2. In the space provided furnish below explanations,including the following:
State the general method or methods of liberalized depreciation being used (sum-of-year digits, declining balance, etc.,) estimated lives i.e. useful life, guideline life, guideline class life, etc., and classes of plant to

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited (Account 410.1) (c)	Amounts Credited (Account 411.1) (d)
1	Account 282			
2	Electric		$ 2,183,209	$ (93,465)
3	Gas			
4	Other (Define)			
5	TOTAL (Enter Total of lines 2 thru 4)		2,183,209	(93,465)
6	Other (Specify)			
7	FERC Jurisdictional Deferral			
8	Non-Utility Property			
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)		$ 2,183,209	$ (93,465)
10	Classification of TOTAL			
11	Federal Income Tax			
12	State Income Tax			
13	Local Income Tax			

Line 2:		
Depr for Tax GT or LT Book	-	-
Intangible Asset - Labor Deduction	23,968	-
N Valmy Partnership Capitalized Itmes	-	(3,293)
Bridger Partnership Capitalized Items	-	-
CIAC as Taxable Income	9,970	(88,432)
FERC JURiS-S. GEORGIA-ACCT 282-DEF ONLY	-	-
Engineering Fees	368	(1,739)
Software Costs	(2,853)	-
FERC JURIS-144A-ACCT 282-DEF ONLY	-	-
Liberalized Depreciation - Electric Plant	2,151,755	-
Total	2,183,209	(93,465)

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

which each method is being applied and date method was adopted.

3.Beginning balance may be omitted if not readily available. Report electric utility deferred taxes only.

4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year (k)	Line No.
Amounts Debited (Account 410.2) (e)	Amounts Credited (Account 411.2) (f)	Debits Acct. No. (g)	Debits Amount (h)	Credits Acct. No. (i)	Credits Amount (j)		
							1
$ -	$ -				$ -		2
							3
							4
0	0				0		5
							6
							7
$ -	$ -						8
$ -	$ -				$ -		9
							10
							11
							12
							13

ACCUMULATED DEFERRED INCOME TAXES-OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. In the space provided below include amounts relating to insignificant items under Other.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited (Account 410.1) (c)	CHANGES DURING YEAR Amounts Credited (Account 411.1) (d)
1	Account 283			
2	Electric (See Note 1)		2,975,140	(2,584,579)
3				
4	Total Electric		2,975,140	(2,584,579)
5				
6				
7	Other (See Note 2)			
8				
9				
10	Total (Account 283) (Enter Total of lines 4 - 9)		$ 2,975,140	$ (2,584,579)
11	Classification of Total			
12	Federal Income Tax			
13	State Income Tax			
14	Local Income Tax			
	Note 1:			
	Oregon PCAM		6,821	(33,201)
	FERC Grid West Expense		0	(1,811)
	PCA Expense Deferral		314,725	(988,293)
	Conservation Programs		132,865	(362,075)
	Oregon Excess Power Supply Costs		45,820	(93,992)
	IPUC Grid West Loans		0	(4,029)
	Emission Allowances		7,903	(2,644)
	Fixed Cost Adjustment (FCA)		246,334	(200,613)
	OPUC Grid West Loans		0	(307)
	Intervenor Funding Orders		1,186	(0)
	Bonus Deferral		28	(673)
	Reorganization Costs		0	(4,984)
	Delivery Accruals		1,843	(2,165)
	Green Tag Sales		90,872	(43,357)
	Pension Expense		1,956,715	(846,437)
	LIDAR Surveys Deferral		9,423	0
	Bennett Mtn Maintenance Deferral		6,473	0
	Custom Efficiency Incentive Payment		153,347	0
	PS&I Costs - Coal & CHP Plants - Write Off		787	(0)
	Total		2,975,140	(2,584,579)
	Note 2:			
	Advance Coal Royalties			
	Oregon Non-Operating Property Tax Adj			
	Unrealized Gain/Loss from Rabbi Trust			
	Total			

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

3. Beginning balances may be omitted if not readily available. Report electric utility deferred taxes only.

4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited (Account 410.2)	Amounts Credited (Account 411.2)	Debits		Credits			
		Acct. No.	Amount	Acct. No.	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
0	0						2
							3
-	-		-		-		4
							5
							6
(11,762)	(2,031)						7
							8
							9
$ (11,762)	$ (2,031)		$ -		$ -		10
							11
							12
							13
							14

0	0
(438)	0
(18)	(18)
(11,305)	(2,013)
(11,762)	(2,031)

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. 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)	Balance at End Year (h)	Average Period of Allocation To Income (i)
1	Electric Utility								
2	3%								
3	4%								
4	7%								
5	10%								
6									
7									
8									
9	TOTAL		411.4	$ 95,696	411.4	$ 144,427			
10									
11	Other (List separately								
12	and show 3%, 4%, 7%,								
13	10% and TOTAL)								
14									
15									
16									
17									
18									
19									
20									
21									
22									
23									
24									
25									
26									
27									
28									
29									

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

Line No.	Item (a)	Total (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Common (g)
1	UTILITY PLANT						
2	In Service						
3	Plant in Service (Classified)	$ 420,307,568	$ 420,307,568				
4	Property Under Capital Leases						
5	Plant Purchased or Sold						
6	Completed Construction not Classified						
7	Experimental Plant Unclassified						
8	TOTAL (Enter Total of lines 3 thru 7)	$ 420,307,568	$ 420,307,568				
9	Leased to Others						
10	Held for Future Use	$ 89,977	$ 89,977				
11	Construction Work in Progress	$ 10,531,699	$ 10,531,699				
12	Acquisition Adjustments						
13	TOTAL Utility Plant (Enter Total of lines 8 thru 12)	$ 430,929,245	$ 430,929,245				
14	Accum. Prov. for Depr., Amort., & Depl	NOT AVAILABLE					
15	Net Utility Plant (Enter Total of line 13 less 14)	$ 430,929,245	$ 430,929,245				
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION						
17	In Service						
18	Depreciation	NOT AVAILABLE					
19	Amort. and Depl. of Producing Natural Gas Land and Land Rights						
20	Amort. of Underground Storage Land and Land Rights						
21	Amort. of Other Utility Plant						
22	TOTAL In Service (Enter total of lines 18 thru 21)						
23	Leased to Others						
24	Depreciation						
25	Amortization and Depletion						
26	TOTAL Leased to Others (Enter Total of lines 24 and 25)						
27	Held for Future Use						
28	Depreciation						
29	Amortization						
30	TOTAL Held for Future Use (Enter Total of lines 28 and 29)						
31	Abandonment of Leases (Natural Gas)						
32	Amort. of Plant Acquisition Adj.						
33	TOTAL Accumulated Provisions (Should agree with line 14 above) (Enter Total of lines 22,26,30,31,and 32)						

ELECTRIC PLANT IN SERVICE

(In addition to Account 101, Electric Plant in Service [Classified], this schedule includes Account 102, Electric Plant Purchased or Sold, Account 103, Experimental Electric Plant Unclassified and Account 106, Completed Construction Not Classified-Electric.)

1. Report below the original cost of electric plant in service according to prescribed accounts.

2. Do not include as adjustments, corrections of additions and retirements for the current or the preceding year. Such items should be included in column (c) or (d) as appropriate.

3. Credit adjustments of plant accounts should be enclosed in parentheses to indicate the negative effect of such amounts.

4. Reclassifications or transfers within utility plant accounts should be shown in column (f). Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, Electric Plant Purchased or Sold. In showing the clearance of Account 102, include in column (c) 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.

Line No.	Account (a)	Balance at Beginning of year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
1	1. INTANGIBLE PLANT								1
2	(301) Organization	$ 1,230	$	$	$	$	$ 1,230	(301)	2
3	(302) Franchises and Consents	235,168	5,855				$ 241,023	(302)	3
4	(303) Miscellaneous Intangible Plant							(303)	4
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	236,398	5,855	0	0	0	242,253		5
6	2. PRODUCTION PLANT								6
7	A. Steam Production Plant								7
8	(310) Land and Land Rights	106,610					106,610	(310)	8
9	(311) Structures and Improvements	13,810,712	34,314	(5,194)			13,839,832	(311)	9
10	(312) Boiler Plant Equipment	37,360,898	3,464,881	(240,809)			40,584,970	(312)	10
11	(313) Engines and Engine Driven Generators	0					0	(313)	11
12	(314) Turbogenerator Units	13,857,615	8,551	(53)			13,866,113	(314)	12
13	(315) Accessory Electric Equipment	4,565,841	99,438	(2,809)			4,662,470	(315)	13
14	(316) Misc. Power Plant Equipment	1,841,121	20,996	(87,401)			1,774,715	(316)	14
15	(317) Asset Retirement Costs for Steam Production	95,710	4,241,816				4,337,526	(317)	15
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	71,638,507	7,869,995	(336,266)	0	0	79,172,236		16
17	B. Nuclear Production Plant								17
18	(320) Land and Land Rights	0					0	(320)	18
19	(321) Structures and Improvements	0					0	(321)	19
20	(322) Reactor Plant Equipment	0					0	(322)	20
21	(323) Turbogenerator Units	0					0	(323)	21
22	(324) Accessory Electric Equipment	0					0	(324)	22
23	(325) Misc. Power Plant Equipment	0					0	(325)	23
24	(326) Asset Retirement Csts for Nuclear Productions	0					0	(326)	
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	0	0	0	0	0	0		25
26	C. Hydraulic Production Plant								26
27	(330) Land and Land Rights	10,334,723					10,334,723	(330)	27
28	(331) Structures and Improvements	17,101,678	218,747				17,320,425	(331)	28
29	(332) Reservoirs, Dams, and Waterways	91,196,492	91,070				91,287,562	(332)	29
30	(333) Water Wheels, Turbines, and Generators	22,905,309	100,713	(46,811)			22,959,211	(333)	30
31	(334) Accessory Electric Equipment	6,979,892	(158)	(16,523)			6,963,211	(334)	31
32	(335) Misc. Power Plant Equipment	2,733,542	636,556				3,370,098	(335)	32
33	(336) Roads, Railroads, and Bridges	1,388,105					1,388,105	(336)	33
34	(337) Asset Retirement Costs for Hydraulic Production	0					0	(337)	34
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	152,639,740	1,046,929	(63,334)		0	153,623,335		35

ELECTRIC PLANT IN SERVICE

(In addition to Account 101, Electric Plant in Service [Classified], this schedule includes Account 102, Electric Plant Purchased or Sold, Account 103, Experimental Electric Plant Unclassified and Account 106, Completed Construction Not Classified-Electric.)

1. Report below the original cost of electric plant in service according to prescribed accounts.

2. Do not include as adjustments, corrections of additions and retirements for the current or the preceding year. Such items should be included in column (c) or (d) as appropriate.

3. Credit adjustments of plant accounts should be enclosed in parentheses to indicate the negative effect of such amounts.

4. Reclassifications or transfers within utility plant accounts should be shown in column (f). Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, Electric Plant Purchased or Sold. In showing the clearance of Account 102, include in column (c) 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.

Line No.	Account (a)	Balance at Beginning of year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
36	D. Other Production Plant								36
37	(340) Land and Land Rights	$	$	$	$	$	$	(340)	37
38	(341) Structures and Improvements	0					0	(341)	38
39	(342) Fuel Holders, Products and Accessories	0					0	(342)	39
40	(343) Prime Movers	0					0	(343)	40
41	(344) Generators	0					0	(344)	41
42	(345) Accessory Electric Equipment	0					0	(345)	42
43	(346) Misc. Power Plant Equipment	0					0	(346)	43
44	(347) Asset Retirement Costs for Hydraulic Production	0					0	(347)	44
45	TOTAL Other Production Plant (Enter Total of lines 36 thru 44)	0	0	0	0	0	0		45
46	TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 45)	224,278,247	8,916,924	(399,600)	0	0	232,795,571		46
47	3. TRANSMISSION PLANT								47
48	(350) Land and Land Rights	4,385,646	$ 189,190				4,574,835	(350)	48
49	(352) Structures and Improvements	6,055,532	53,236	(2,741)			6,106,028	(352)	49
50	(353) Station Equipment	29,348,744	1,211,682	(31,276)			30,529,149	(353)	50
51	(354) Towers and Fixtures	13,641,691	598,813				14,240,505	(354)	51
52	(355) Poles and Fixtures	16,606,075	754,787	(16,202)			17,344,660	(355)	52
53	(356) Overhead Conductors and Devices	15,449,812	201,379	(42,075)			15,609,116	(356)	53
54	(357) Underground Conduit	0					0	(357)	54
55	(358) Underground Conductors and Devices	0					0	(358)	55
56	(359) Roads and Trails	38,450	14,748				53,198	(359)	56
57	(359.1) Asset Retirement Costs for Transmission Plant	0					0	(359.1)	57
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	85,525,951	3,023,835	(92,295)	0	0	88,457,492		58
59	4. DISTRIBUTION PLANT								59
60	(360) Land and Land Rights	148,192					148,192	(360)	60
61	(361) Structures and Improvements	1,284,519	656	(1,947)			1,283,228	(361)	61
62	(362) Station Equipment	7,462,940	256,951	(27,104)			7,692,788	(362)	62
63	(363) Storage Battery Equipment	0					0	(363)	63
64	(364) Poles, Towers, and Fixtures	16,783,940	910,777	(223,407)			17,471,311	(364)	64
65	(365) Overhead Conductors and Devices	7,241,570	984,211	(117,243)			8,108,539	(365)	65
66	(366) Underground Conduit	705,333	(4,403)	(2,441)			698,490	(366)	66
67	(367) Underground Conductors and Devices	3,246,279	(23,822)	(29,141)			3,193,316	(367)	67
68	(368) Line Transformers	37,726,492	1,493,992	(116,935)			39,103,549	(368)	68
69	(369) Services	2,944,793	(27,270)	(16,298)			2,901,225	(369)	69
70	(370) Meters	8,704,165	1,533,960	(104)			10,238,020	(370)	70
71	(371) Installations on Customer Premises	233,021	7,244	(15,413)			224,852	(371)	71
72	(372) Leased Property on Customer Premises	0	0				0	(372)	72
73	(373) Street Lighting and Signal Systems	213,660	4,156	(4,666)			213,150	(373)	73
74	(374) Asset Retirement Cost for Distribution Plant	0					0	(374)	74
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	86,694,906	5,136,451	(554,697)	0	0	91,276,660		75

ELECTRIC PLANT IN SERVICE

(In addition to Account 101, Electric Plant in Service [Classified], this schedule includes Account 102, Electric Plant Purchased or Sold, Account 103, Experimental Electric Plant Unclassified and Account 106, Completed Construction Not Classified-Electric.)

1. Report below the original cost of electric plant in service according to prescribed accounts.

2. Do not include as adjustments, corrections of additions and retirements for the current or the preceding year. Such items should be included in column (c) or (d) as appropriate.

3. Credit adjustments of plant accounts should be enclosed in parentheses to indicate the negative effect of such amounts.

4. Reclassifications or transfers within utility plant accounts should be shown in column (f). Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, Electric Plant Purchased or Sold. In showing the clearance of Account 102, include in column (c) 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.

Line No.	Account (a)	Balance at Beginning of year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
76	5. GENERAL PLANT								76
77	(389) Land and Land Rights	8,243					8,243	(389)	77
78	(390) Structures and Improvements	499,096					499,096	(390)	78
79	(391) Office Furniture and Equipment	49,613	3,755	(9,126)			44,242	(391)	79
80	(392) Transportation Equipment	2,103,317	90,323				2,193,640	(392)	80
81	(393) Stores Equipment	0					0	(393)	81
82	(394) Tools, Shop and Garage Equipment	0	4,129				4,129	(394)	82
83	(395) Laboratory Equipment	57,894	11,259				69,153	(395)	83
84	(396) Power Operated Equipment	1,502,710	24,455				1,527,165	(396)	84
85	(397) Communication Equipment	2,984,470	183,148	(2,014)			3,165,604	(397)	85
86	(398) Miscellaneous Equipment	24,321					24,321	(398)	86
87	SUBTOTAL (Enter Total of lines 77 thru 86)	7,229,664	317,068	(11,139)	0	0	7,535,592		87
88	(399) Other Tangible Property *	0					0	(399)	88
90	(399.1) Asset Retirement Costs for General Plant	0					0	(399.1)	90
91	TOTAL General Plant (Enter Total of lines 87 thru 90)	7,229,664	317,068	(11,139)	0	0	7,535,592		91
92	TOTAL (Accounts 101 and 106)	403,965,167	17,400,133	(1,057,731)	0	0	420,307,568		92
93	(102) Electric Plant Purchased **								93
94	(Less) (102) Electric Plant Sold **								94
95	(103) Experimental Electric Plant Unclassified								95
96	TOTAL Electric Plant in Service	$ 403,965,167	$ 17,400,133	$ (1,057,731)	$	$	$ 420,307,568		96

* State the nature and use of plant included in this account and if substantial in amount submit a supplementary schedule showing subaccount classification of such plant conforming to the requirements of this schedule.

** For each amount comprising the reported balance and charges 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.

NOTE

Completed Construction Not Classified, Account 106, shall be classified in this schedule according to prescribed accounts, on an estimated basis if necessary, and the entries included in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (c). Likewise, if respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, a tentative distribution of such retirements, on an estimated basis with appropriate contra entry to the account for accumulated depreciation provision, shall be included in column (d). Include also in column (d) reversals of tentative distributions of prior year of unclassified retirements. Attach an insert page 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.

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

1. Report below the information called for concerning accumulated provision for depreciation of electric utility plant.
2. Explain any important adjustments during year.
3. Explain any difference between the amount for book cost of plant retired, line.., column (c), and that reported in the schedule for electric plant in service, pages 401-403, column (d) exclusive of retirements of nondepreciable property.
4. The provisions of account 108 in the Uniform System of Accounts contemplate 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, preliminary closing entries should be made to tentatively functionalize the book cost of the plant retired. In addition, all cost included in retirement work in progress at year end should be included in the appropriate functional classifications.
5. Show separately interest credits under a sinking fund or similar method of depreciation accounting.
6. In section B show the amounts applicable to prescribed functional classifications.

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				
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense				
4	(413) Exp. of Elec. Plt. Leas. to Others				
5	Transportation Expenses-Clearing	INFORMATION NOT AVAILABLE BY STATE ON A SITUS BASIS.			
6	Other Clearing Accounts				
7	Other Accounts (Specify):				
8					
9	TOTAL Deprec. Prov. for Year (Enter Total of lines 3 thru 8)				
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired				
12	Cost of Removal				
13	Salvage (Credit)				
14	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 11 thru 13)				
15	Other Debit or Credit Items (Describe)				
16	Balance End of Year (Enter Total of				
17	lines 1, 9, 14, 15, and 16)				

Section B. Balances at End of Year According to Functional Classifications

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)
18	Steam Production				
19	Nuclear Production				
20	Hydraulic Production - Conventional				
21	Hydraulic Production - Pumped Storage				
22	Other Production				
23	Transmission				
24	Distribution				
25	General				
26	TOTAL (Enter Total of lines 18 thru 25)				

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 year (on a supplemental page) showing general classes of material and supplies and the various accounts (operating expense, clearing accounts, plant, etc.) affected - debited or credited. Show separately debits or credits to stores expense-clearing, if applicable.

Line No.	Account (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)	Department or Departments Which Use Material (d)
1	Fuel Stock (Account 151)			
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	INFORMATION NOT AVAILABLE BY STATE ON A SITUS BASIS.		
7	Production Plant (Estimated)			
8	Transmission Plant (Estimated)			
9	Distribution Plant (Estimated)			
10	Assigned to - Other			
11	TOTAL Account 154 (Enter Total of lines 5 thru 10)			
12	Merchandise (Account 155)			
13	Other Materials and Supplies (Account 156)			
14	Nuclear Materials Held for Sale (Account 157) (Not applicable to Gas Utilities)			
15	Stores Expense Undistributed (Account 163)			
16				
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)			

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

Line No.	Item (a)	Total (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Common (g)
1	UTILITY PLANT						
2	In Service						
3	Plant in Service (Classified)	$ 192,326,578	$ 192,326,578				
4	Property Under Capital Leases						
5	Plant Purchased or Sold						
6	Completed Construction not Classified						
7	Experimental Plant Unclassified						
8	TOTAL (Enter Total of lines 3 thru 7)	192,326,578	192,326,578				
9	Leased to Others						
10	Held for Future Use	$ 268,461	268,461				
11	Construction Work in Progress						
12	Acquisition Adjustments						
13	TOTAL Utility Plant (Enter Total of lines 8 thru 12)	192,595,039	192,595,039				
14	Accum. Prov. for Depr., Amort., & Depl	$ 80,768,467	80,768,467				
15	Net Utility Plant (Enter Total of line 13 less 14)	$ 111,826,573	$ 111,826,573				
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION						
17	In Service						
18	Depreciation	$ 79,795,394	$ 79,795,394				
19	Amort. and Depl. of Producing Natural Gas Land and Land Rights						
20	Amort. of Underground Storage Land and Land Rights						
21	Amort. of Other Utility Plant	$ 973,072	973,072				
22	TOTAL In Service (Enter total of lines 18 thru 21)	80,768,467	80,768,467				
23	Leased to Others						
24	Depreciation						
25	Amortization and Depletion						
26	TOTAL Leased to Others (Enter Total of lines 24 and 25)						
27	Held for Future Use						
28	Depreciation						
29	Amortization						
30	TOTAL Held for Future Use (Enter Total of lines 28 and 29)						
31	Abandonment of Leases (Natural Gas)						
32	Amort. of Plant Acquisition Adj						
33	TOTAL Accumulated Provisions (Should agree with line 14 above) (Enter Total of lines 22,26,30,31,and 32)	$ 80,768,467	$ 80,768,467				

ELECTRIC PLANT IN SERVICE

(In addition to Account 101, Electric Plant in Service [Classified], this schedule includes Account 102, Electric Plant Purchased or Sold, Account 103, Experimental Electric Plant Unclassified and Account 106, Completed Construction Not Classified-Electric.)

1. Report below the original cost of electric plant in service according to prescribed accounts.

2. Do not include as adjustments, corrections of additions and retirements for the current or the preceding year. Such items should be included in column (c) or (c) as appropriate.

ELECTRIC PLANT IN SERVICE (Continued)

3. Credit adjustments of plant accounts should be enclosed in parentheses to indicate the negative effect of such amounts.

4. Reclassifications or transfers within utility plant accounts should be shown in column (f). Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, Electric Plant Purchased or Sold. In showing the clearance of Account 102, include in column (c) 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.

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
1	1. INTANGIBLE PLANT								1
2	(301) Organization	$ 270					$ 246	(301)	2
3	(302) Franchises and Consents	988,448					999,187	(302)	3
4	(303) Miscellaneous Intangible Plant	1,562,263					1,477,397	(303)	4
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	$ 2,550,981					$ 2,476,829		5
6	2. PRODUCTION PLANT								6
7	A. Steam Production Plant								7
8	(310) Land and Land Rights							(310)	8
9	(311) Structures and Improvements							(311)	9
10	(312) Boiler Plant Equipment							(312)	10
11	(313) Engines and Engine Driven Generators							(313)	11
12	(314) Turbogenerator Units							(314)	12
13	(315) Accessory Electric Equipment							(315)	13
14	(316) Misc. Power Plant Equipment							(316)	14
15	(317) Asset Retirement Costs for Steam Production Equipment							(317)	15
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	$ 38,999,709					$ 40,573,412		16
17	B. Nuclear Production Plant								17
18	(320) Land and Land Rights							(320)	18
19	(321) Structures and Improvements							(321)	19
20	(322) Reactor Plant Equipment							(322)	20
21	(323) Turbogenerator Units							(323)	21
22	(324) Accessory Electric Equipment							(324)	22
23	(325) Misc. Power Plant Equipment							(325)	23
24	(326) Asset Retirement Costs for Nuclear Production							(326)	
25	TOTAL Nuclear Production Plant (Enter Total of lines 17 thru 24)								25
26	C. Hydraulic Production Plant								26
27	(330) Land and Land Rights							(330)	27
28	(331) Structures and Improvements							(331)	28
29	(332) Reservoirs, Dams, and Waterways							(332)	29
30	(333) Water Wheels, Turbines, and Generators							(333)	30

ELECTRIC PLANT IN SERVICE

(In addition to Account 101, Electric Plant in Service [Classified], this schedule includes Account 102, Electric Plant Purchased or Sold, Account 103, Experimental Electric Plant Unclassified and Account 106, Completed Construction Not Classified-Electric.)

1. Report below the original cost of electric plant in service according to prescribed accounts.

2. Do not include as adjustments, corrections of additions and retirements for the current or the preceding year. Such items should be included in column (c) or (c) as appropriate.

ELECTRIC PLANT IN SERVICE (Continued)

3. Credit adjustments of plant accounts should be enclosed in parentheses to indicate the negative effect of such amounts.

4. Reclassifications or transfers within utility plant accounts should be shown in column (f). Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, Electric Plant Purchased or Sold. In showing the clearance of Account 102, include in column (c) 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.

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
31	(334) Accessory Electric Equipment							(334)	31
32	(335) Misc. Power Plant Equipment							(335)	32
33	(336) Roads, Railroads, and Bridges							(336)	33
34	(337) Asset Retirement Costs for Hydraulic Production							(326)	34
35	TOTAL Hydraulic Production Plant (Enter Total of lines 26 thru 34)	$ 29,865,495					$ 30,625,770		35
36	D. Other Production Plant								36
37	(340) Land and Land Rights	$					$	(340)	37
38	(341) Structures and Improvements							(341)	38
39	(342) Fuel Holders, Products and Accessories							(342)	39
40	(343) Prime Movers							(343)	40
41	(344) Generators							(344)	41
42	(345) Accessory Electric Equipment							(345)	42
43	(346) Misc. Power Plant Equipment							(346)	43
44	(347) Asset Retirement Costs for Other Production							(347)	44
45	TOTAL Other Production Plant (Enter Total of lines 36 thru 44)	$ 7,460,439					$ 7,466,721		45
46	TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 45)	76,325,644					78,665,903		46
47	3. TRANSMISSION PLANT								47
48	(350) Land and Land Rights	1,306,355					1,514,887	(350)	48
49	(352) Structures and Improvements	2,126,533					2,501,457	(352)	49
50	(353) Station Equipment	13,455,574					15,207,233	(353)	50
51	(354) Towers and Fixtures	5,519,374					6,360,063	(354)	51
52	(355) Poles and Fixtures	3,908,127					4,647,552	(355)	52
53	(356) Overhead Conductors and Devices	6,475,825					7,432,536	(356)	53
54	(357) Underground Conduit							(357)	54
55	(358) Underground Conductors and Devices							(358)	55
56	(359) Roads and Trails	12,141					17,824	(359)	56
57	(359.1) Asset Retirement Costs for Transmission Plant							(359.1)	57
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	$ 32,803,930					$ 37,681,551		58
59	4. DISTRIBUTION PLANT								59
60	(360) Land and Land Rights	192,969					135,436	(360)	60
61	(361) Structures and Improvements	1,196,342					1,186,872	(361)	61
62	(362) Station Equipment	7,333,705					6,704,195	(362)	62
63	(363) Storage Battery Equipment	0					0	(363)	63
64	(364) Poles, Towers, and Fixtures	16,783,940					17,471,311	(364)	64
65	(365) Overhead Conductors and Devices	7,241,570					8,108,539	(365)	65
66	(366) Underground Conduit	705,333					698,490	(366)	66
67	(367) Underground Conductors and Devices	3,246,279					3,193,316	(367)	67
68	(368) Line Transformers	37,726,492					18,029,600	(368)	68
69	(369) Services	2,944,793					2,901,225	(369)	69
70	(370) Meters	3,489,514					2,602,462	(370)	70
71	(371) Installations on Customer Premises	233,021					224,852	(371)	71

ELECTRIC PLANT IN SERVICE

(In addition to Account 101, Electric Plant in Service [Classified], this schedule includes Account 102, Electric Plant Purchased or Sold, Account 103, Experimental Electric Plant Unclassified and Account 106, Completed Construction Not Classified-Electric.)

1. Report below the original cost of electric plant in service according to prescribed accounts.

2. Do not include as adjustments, corrections of additions and retirements for the current or the preceding year. Such items should be included in column (c) or (c) as appropriate.

ELECTRIC PLANT IN SERVICE (Continued)

3. Credit adjustments of plant accounts should be enclosed in parentheses to indicate the negative effect of such amounts.

4. Reclassifications or transfers within utility plant accounts should be shown in column (f). Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, Electric Plant Purchased or Sold. In showing the clearance of Account 102, include in column (c) 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.

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
72	(372) Leased Property on Customer Premises							(372)	72
73	(373) Street Lighting and Signal Systems	213,660					213,150	(373)	73
74	(374) Asset Retirement Costs for Distribution Plant							(374)	74
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	$ 81,307,618					$ 61,469,446		75
76	5. GENERAL PLANT								76
77	(389) Land and Land Rights	526,876					694,360	(389)	77
78	(390) Structures and Improvements	3,660,291					3,658,707	(390)	78
79	(391) Office Furniture and Equipment	1,865,017					1,746,091	(391)	79
80	(392) Transportation Equipment	2,887,235					2,625,189	(392)	80
81	(393) Stores Equipment	69,121					68,884	(393)	81
82	(394) Tools, Shop, and Garage Equipment	263,705					260,676	(394)	82
83	(395) Laboratory Equipment	565,854					510,861	(395)	83
84	(396) Power Operated Equipment	469,963					460,498	(396)	84
85	(397) Communication Equipment	1,383,724					1,408,396	(397)	85
86	(398) Miscellaneous Equipment	225,580					226,235	(398)	86
87	SUBTOTAL (Enter Total of lines 77 thru 86)	11,917,366					11,659,897		87
88	(399) Other Tangible Property *							(399)	88
89	(399.1) Asset Retirement Costs for General Plant							(399.1)	89
90	TOTAL General Plant (Enter Total of lines 87, 88 and 89)	11,917,366					11,659,897		90
91	TOTAL (Accounts 101 and 106)	204,905,539					191,953,625		91
92	(102) Electric Plant Purchased **								92
93	(Less) (102) Electric Plant Sold **								93
94	Asset Retirement Obligations (ARO)	175,112					372,953		94
95	TOTAL Electric Plant in Service	$ 205,080,651					$ 192,326,578		95

* State the nature and use of plant included in this account and if substantial in amount submit a supplementary schedule showing subaccount classification of such plant conforming to the requirements of this schedule.

** For each amount comprising the reported balance and charges 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.

NOTE

Completed Construction Not Classified, Account 106, shall be classified in this schedule according to prescribed accounts, on an estimated basis if necessary, and the entries included in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (c). 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, a tentative distribution of such retirements, on an estimated basis with appropriate contra entry to the account for accumulated depreciation provision, shall be included in column (d). Include also in column (d) reversals of tentative distributions of prior year of unclassified retirements. Attach an insert page 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.

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

1. Report below the information called for concerning accumulated provision for depreciation of electric utility plant.
2. Explain any important adjustments during year.
3. Explain any difference between the amount for book cost of plant retired, line.., column (c), and that reported in the schedule for electric plant in service, pages 401-403, column (d) exclusive of retirements of nondepreciable property.
4. The provisions of account 108 in the Uniform System of Accounts contemplate 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, preliminary closing entries should be made to tentatively functionalize the book cost of the plant retired. In addition, all cost included in retirement work in progress at year end should be included in the appropriate functional classifications.
5. Show separately interest credits under a sinking fund or similar method of depreciation accounting.
6. In section B show the amounts applicable to prescribed functional classifications.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	$	$		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	4,753,703	4,753,703		
4	(413) Exp. of Elec. Plt. Leas. to Others				
5	Transportation Expenses-Clearing				
6	Other Clearing Accounts				
7	Other Accounts (Specify)				
8					
9	TOTAL Deprec. Prov. for Year (Enter Total of lines 3 thru 8)	4,753,703	4,753,703		
10	Net Charges for Plant Retired				
11	Book Cost of Plant Retired				
12	Cost of Removal				
13	Salvage (Credit)				
14	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 11 thru 13)				
15	Other Debit or Credit Items (Describe)				
16	Balance End of Year (Enter Total of				
17	lines 1, 9, 14, 15, and 16)	$ 4,753,703	$ 4,753,703		

Section B. Balances at End of Year According to Functional Classifications

Line No.	Item (a)	Total (c+d+e) (b)	Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
18	Steam Production	$ 22,654,513	$ 22,654,513		
19	Nuclear Production				
20	Hydraulic Production - Conventional	15,212,331	15,212,330.62		
21	Hydraulic Production - Pumped Storage				
22	Other Production	1,313,557	1,313,557		
23	Transmission	11,696,979	11,696,979		
24	Distribution	24,137,857	24,137,857		
25	General	4,361,384	4,361,384		
26	FAS 143 Adj &/or Disallowed Cost	418,773	418,773		
27	TOTAL (Enter Total of lines 18 thru 26)	$ 79,795,394	$ 79,795,394		

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 year (on a supplemental page) showing general classes of material and supplies and the various accounts (operating expense, clearing accounts, plant, etc.) affected - debited or credited. Show separately debits or credits to stores expense-clearing, if applicable.

Line No.	Account (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)	Department or Departments Which Use Material (d)
1	Fuel Stock (Account 151)	$ 1,268,016	$ 2,199,546	
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)	615,128	638,580	
8	Transmission Plant (Estimated)	512,681	558,355	
9	Distribution Plant (Estimated)	799,791	560,911	
10	Assigned to - Other	42,494	51,713	
11	TOTAL Account 154 (Enter Total of lines 5 thru 10)	1,970,094	1,809,559	
12	Merchandise (Account 155)			
13	Other Materials and Supplies (Account 156)			
14	Nuclear Materials Held for Sale (Account 157) (Not applicable to Gas Utilities)			
15	Stores Expense Undistributed (Account 163)	159,996	192,644	
16				
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	$ 3,398,106	$ 4,201,748	

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, and interchanged during the year.

Line No.	Item (a)	Megawatt Hours (b)	Line No.	Item (a)	Megawatt Hours (b)
1	SOURCES OF ENERGY		20	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		21	Sales to Ultimate Consumers (Including Interdepartmental Sales)	
3	Steam........... Steam				
4	Nuclear		22	Sales for Resale	
5	Hydro-Conventional		23	Energy Furnished Without Charge	
6	Hydro-Pumped Storage	INFORMATION	24	Energy Used by the Company (Excluding Station Use):	INFORMATION
7	Other				
8	Less Energy for Pumping	NOT	25	Electric Department Only	NOT
9	Net Generation (Enter Total of lines 3 thru 8)	AVAILABLE	26	Energy Losses:	AVAILABLE
10	Purchases		27	Transmission and Conversion Losses	
11	Interchanges:		28	Distribution Losses	
12	In (gross)		29	Unaccounted for Losses	
13	Out (gross)		30	TOTAL Energy Losses	
14	Net Interchanges (Lines 12 & 13)		31	Energy Losses as Percent of Total on Line 19	
15	Transmission for/by Others (Wheeling)				
16	Received (MWh)		32	TOTAL (Enter Total of lines 21, 22, 23, 25, and 30)	
17	Delivered (MWh)				
18	Net Transmission (lines 16 & 17)				
19	TOTAL (Enter Total of lines 9, 10, 14, and 18)				

MONTHLY PEAKS AND OUTPUT

1. Report below the information called for pertaining to simultaneous peaks established monthly (in megawatts) and monthly output (in megawatt-hours) for the combined sources of electric energy of respondent.
2. Report in column (b) the respondent's maximum MW load as measured by the sum of its coincidental net generation and purchases plus or minus net interchange, minus temporary deliveries (not interchange) Show monthly peak including such emergency deliveries of emergency power to another system. in a footnote and briefly explain the nature of the emergency. There may be cases of commingling of purchases and exchanges and "wheeling," also of direct deliveries by the supplier to customers of the reporting utility wherein segregation of MW demand for determination of peaks as specified by this report may be unavailable. In these cases, report peaks which include these intermingled transactions. Furnish an explanatory note which indicates, among other things, the relative significance of the deviation from basis otherwise applicable. If the individual MW amounts of such totals are needed for billing under separate rate schedules and are estimated, give the amount and basis of estimate.
3. State type of monthly peak reading (instantaneous 15, 30, or 60 minutes integrated).
4. Monthly output is the sum of respondent's net generation for load and purchases plus or minus net interchange and plus or minus net transmission or wheeling. Total for the year must agree with line 19 above.
5. If the respondent has two or more power systems not physically connected, furnish the information called for below for each system.

NAME OF SYSTEM: OREGON RETAIL ONLY

Line No.	Month (a)	MONTHLY PEAK Megawatts (b)	Day of Week (c)	Day of Month (d)	Hour (e)	Type of Reading (f)	Monthly Output (MWh) (See Instr. 4) (g)
33	January	100.44	Tuesday	4	8 AM	60 Min. Int	62,373
34	February	102.43	Wednesday	2	8 AM	" " "	51,375
35	March	97.71	Tuesday	8	8 AM	" " "	59,213
36	April	87.83	Wednesday	6	8 AM	" " "	48,201
37	May	79.06	Monday	16	11 AM	" " "	46,114
38	June	111.22	Tuesday	28	7 PM	" " "	58,502
39	July	104.95	Wednesday	6	8 PM	" " "	67,374
40	August	117.74	Thursday	25	5 PM	" " "	70,006
41	September	98.95	Wednesday	7	6 PM	" " "	55,416
42	October	100.75	Saturday	1	6 PM	" " "	55,476
43	November	102.60	Wednesday	16	8 AM	" " "	59,699
44	December	101.00	Thursday	8	8 AM	" " "	59,069
45	TOTAL	1,204.68					692,819

MISCELLANEOUS GENERAL EXPENSES (Account 930.2)

Report below the information called for concerning items included in miscellaneous general expenses.

Line No.	Items (a)	Total (b)	Amount Applicable to Oregon (c)	Amount Applicable to Other States (d)
1	Industry association dues	$ 405,549	$ 18,502	$ 387,047
2	Nuclear power research expenses (elec.)			
3	Other experimental and general research expenses			
4	Publishing and distributing information and reports to stockholders;			
5	trustee, registrar, and transfer agent fees and expenses, and other			
6	expenses of servicing outstanding securities of the respondent	1,339,926	61,131	1,278,795
7	Other expenses (items of $1,000 or more must be listed separately show-			
8	ing the (1) purpose, (2) recipient, and (3) amount of such items.			
9	Amounts of less than $1,000 may be grouped by classes if the number			
10	of items so grouped is shown)			
11				
12				
13	Directors' fees and expenses (see detail on page 39)	744,559	33,969	710,590
14				
15	Miscellaneous general management expenses (see detail on page 39)	100,437	4,582	95,855
16				
17	Memberships and contributions (see detail on page 39)	1,159,650	52,906	1,106,744
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39	**TOTAL**	$ 3,750,121	$ 171,091	$ 3,579,030

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (Continued)

Report below the information called for concerning items included in miscellaneous general expenses.

Line No.	Items (a)	Total (b)	Amount Applicable to Oregon (c)	Amount Applicable to Other States (d)
1	Directors' Fees and Expenses:			
2	Richard Dahl - Fees	$ 81,340	$ 3,711	$ 77,629
3	Richard Reiten - Fees and expenses	58,974	2,691	56,283
4	Christine King-Fees and expenses	69,097	3,152	65,945
5	Thomas Wilford - Fees and expenses	66,240	3,022	63,218
6	Jan Packwood-Fees and expenses	54,390	2,481	51,909
7	Judith Johansen-Fees and expenses	70,719	3,226	67,493
8	Joan Smith - Fees and expenses	75,162	3,429	71,733
9	Gary G Michael - Fees	129,360	5,902	123,458
10	Stephen Allred	67,757	3,091	64,666
11	Robert A Tinstman Fees and expenses	71,520	3,263	68,257
12				
13	SUBTOTAL	744,559	33,969	710,591
14				
15	Miscellaneous General Management Expenses:			
16	Moody's Analytics Inc	28,832	1,315	27,517
17	New York Stock Exchange - Listing service	52,067	2,375	49,692
18	Port of Morrow	5,475	250	5,225
19	PR Newswire	14,063	642	13,421
20	SUBTOTAL	100,437	3,267	68,338
21				
22	Memberships and Contributions:			
23	Associated Taxpayers of Idaho - Membership	22,000	1,004	20,996
24	Chamber of Commerce	104,397	4,763	99,634
25	Corporate Executive Board	46,750	2,133	44,617
26	Idaho Associaton of Commerce and Industry	14,000	639	13,361
27	Idaho Association of Counties	1,000	46	954
28	Idaho Mining Association	6,000	274	5,726
29	Idaho Technoloty Council	10,000	456	9,544
30	Misc Memberships (3)	900	41	859
31	National Assoc of Corp	4,950	226	4,724
32	Northwest Power Pool	91,722	4,185	87,537
33	Pacific NW Utilities-Membership	2,000	91	1,909
34	Western Electricity Coordinating Council	828,246	37,787	790,459
35	Western Energy Institute	26,095	1,191	24,904
36	Wyoming Taxpayers Assoc	1,590	73	1,517
37	SUBTOTAL	1,159,650	47,140	986,111
38				
39	**TOTAL**	$ 2,004,646	$ 37,308	$ 1,967,338

OFFICERS

1. Report below the name, title and salary for the year 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 date change in incumbency was made.

3. Utilities which are required to file similar data with the Securities and Exchange Commission, may substitute a copy of item 4 of Regulation S-K identified as

Line No.	Title (a)	Name of Officer (b)	Salary for year Total	Salary for year Oregon
1				
2	Chief Executive Officer (3)..	J LaMont Keen	635,000	28,970
3				
4	President & Chief Financial Officer (3)...................................	Darrel T Anderson	383,000	17,474
5				
6	Executive Vice President, & Chief Operations Officer (3)........	Dan Minor	360,000	16,424
7				
8	Senior Vice President, Corporate Responsibility (1)................	Ric Gale	240,000	10,949
9				
10	Vice President and Chief Information Officer..........................	Dennis Gribble	212,500	9,695
11				
12	Vice President, Human Resources & Corp Sevices	Luci McDonald	230,000	10,493
13				
14	Senior Vice President, Finance and Treasurer (3).................	Steven R. Keen	230,000	10,493
15				
16	Senior Vice President, General Counsel	Rex Blackburn	270,000	12,318
17				
18	Vice President Chief Risk Officer	Lori Smith	207,500	9,467
19				
20	Senior Vice President, Power Supply......................................	Lisa Grow	240,000	10,949
21				
22	Vice President, Public Affairs..	Jeffrey Malmen	203,000	9,261
23				
24	Vice President, Customer Operations	Warren Kline	212,500	9,695
25				
26	Vice President Engineering and Operations	Vern Porter	195,500	8,919
27				
28	Corporate Controller & Chief Accounting Officer.....................	Ken Petersen	180,000	8,212
29				
30	Vice President, Supply Chain	Naomi Crafton-Shankel	165,000	7,528
31				
32	Corporate Secretary...	Patrick Harrington	165,000	7,528
33				
34	Vice President, Regulatory Affairs (2).....................................	Gregory Said	165,000	7,528
35				
36	(1) Retirement 06/30/2011			
37	(2) Title/Position Change effective 01/08/2011			
38	(3) Title changes effective 01/01/2012			

POLITICAL ADVERTISING

INSTRUCTIONS: List all payments for advertising, the purpose of which is to aid or defeat any measure before the people or to promote or prevent the enactment of any national, state, district or municipal legislation. Give the specific purpose of such advertising, when and where placed, and the account or accounts charged. Report whole dollars only. Provide a total for each account and a grand total.

Description	Account Charged	Amount
None		

POLITICAL CONTRIBUTIONS

INSTRUCTIONS: List all payments or contributions to persons and organizations for the purpose of aiding or defeating any measure before the people or to promote or prevent the enactment of any national, state, district or municipal legislation. The purpose of all contributions or payments should be clearly explained. Report whole dollars only. Provide a total for each account and a grand total.

Description	Account Charged	Amount
ALAN OLSEN FOR STATE SENATE	426.4	$ 300
AVISTA CORP	426.4	208
BERT BRACKETT FOR STATE SENATO	426.4	1,000
BERT STEVENSON FOR STATE REPRE	426.4	500
BRENNEMAN, JOHN	426.4	73,990
BRENT CRANE FOR STATE REPRESEN	426.4	500
BRENT HILL FOR STATE SENATE	426.4	1,000
BRIAN BOQUIST LEADERSHIP FUND	426.4	700
BROWN RUDNICK BERLACK ISRAELS	426.4	72,000
BRUCE STARR FOR SENATE COMMITT	426.4	300
BUSINESS INSTITUTE FOR	426.4	2,500
CANYON COUNTY REPUBLICAN PARTY	426.4	300
CANYON COUNTY REPUBLICANS	426.4	600
CARLOS BILBAO FOR STATE REPRES	426.4	500
CHAMBER OF COMMERCE	426.4	1,500
CHRIS TELFER FOR STATE SENATE	426.4	700
CHUCK WINDER FOR STATE SENATE	426.4	500
CITIZENS FOR JIM THOMPSON	426.4	300
CITIZENS FOR REPRESENTATIVE	426.4	1,000
CITIZENS TO ELECT DENNIS RICHA	426.4	700
COMMITTEE TO ELECT GENE WHISNA	426.4	500
COMMITTEE TO ELECT JASON CONGE	426.4	300
COMMITTEE TO ELECT JEFF KRUSE	426.4	700
COMMITTEE TO ELECT JOHN E HUFF	426.4	300
COMMITTEE TO ELECT LAWRENCE DE	426.4	1,000
COMMITTEE TO ELECT MIKE MCLANE	426.4	300
COMMITTEE TO ELECT SAL ESQUIVE	426.4	300
COMMITTEE TO ELECT WALLY HICKS	426.4	300
COMMITTEE TO RE-ELECT GREG SMI	426.4	500
COMMITTEE TO RE-ELECT PETER BU	426.4	200
CURT MCKENZIE FOR STATE SENATE	426.4	1,000
DEAN CAMERON FOR STATE SENATE	426.4	500
DENTON DARRINGTON FOR STATE SE	426.4	1,000
DICK HARWOOD FOR STATE REPRESE	426.4	500
DONNELLY BIBLE CHURCH	426.4	250
EDGAR MALEPEAI FOR STATE	426.4	1,000
PAGE SUB-TOTAL		**$ 167,748**

POLITICAL CONTRIBUTIONS

INSTRUCTIONS: List all payments or contributions to persons and organizations for the purpose of aiding or defeating any measure before the people or to promote or prevent the enactment of any national, state, district or municipal legislation. The purpose of all contributions or payments should be clearly explained.
Report whole dollars only. Provide a total for each account and a grand total.

Description	Account Charged	Amount
ELAINE SMITH FOR STATE	426.4	$ 500
ERIC ANDERSON FOR STATE REPRES	426.4	500
ERIK SIMPSON FOR STATE REPRESE	426.4	500
FRANK HENDERSON FOR STATE	426.4	500
FRED GIROD FOR STATE SENATE	426.4	1,000
FRED WOOD FOR STATE REPRESENTA	426.4	500
FRIENDS OF ANDY OLSON	426.4	300
FRIENDS OF BRUCE HANNA	426.4	1,000
FRIENDS OF CHUCK THOMSEN	426.4	300
FRIENDS OF DAVID NELSON	426.4	700
FRIENDS OF DOUG WHITSETT	426.4	700
FRIENDS OF JACKIE WINTERS	426.4	300
FRIENDS OF JASON ATKINSON	426.4	700
FRIENDS OF KATIE EYRE BREWER	426.4	300
FRIENDS OF KIM THATCHER	426.4	300
FRIENDS OF LAURIE MONNES ANDER	426.4	200
FRIENDS OF LEE BEYER	426.4	500
FRIENDS OF MARK JOHNSON	426.4	300
FRIENDS OF MITCH TORYANSKI COM	426.4	1,000
FRIENDS OF PHIL BARNHART	426.4	200
FRIENDS OF RICHARD DEVLIN	426.4	200
FRIENDS OF ROD MONROE	426.4	300
FRIENDS OF SHAWN LINDSAY	426.4	500
FRIENDS OF SHERRIE SPRENGER	426.4	300
FRIENDS OF TERRY BEYER COMMITT	426.4	300
FRIENDS OF TIM FREEMAN	426.4	500
FRIENDS OF VIC GILLIAM	426.4	1,000
FRIENDS OF VICKI BERGER	426.4	300
GAYLE BATT FOR STATE REPRESENT	426.4	500
HAHN,RICHARD L	426.4	172,300
HOPKINS RODEN CROCKETT HANSEN	426.4	72,000
HOUSE LEADERSHIP VICTORY FUND	426.4	1,500
IDAHO COUNCIL ON INDUSTRY	426.4	1,000
IDAHO DEMOCRATIC LEGISLATIVE C	426.4	75
IDAHO LEGISLATIVE ADVISOR	426.4	500
IDAHO LIABILITY REFORM COALITI	426.4	1,000
		$ 430,324

POLITICAL CONTRIBUTIONS

INSTRUCTIONS: List all payments or contributions to persons and organizations for the purpose of aiding or defeating any measure before the people or to promote or prevent the enactment of any national, state, district or municipal legislation. The purpose of all contributions or payments should be clearly explained.
Report whole dollars only. Provide a total for each account and a grand total.

Description	Account Charged	Amount
IDAHO MINING ASSOCIATION	426.4	$ 275
IDAHO PETROLEUM COUNCIL	426.4	1,000
IDAHO PRIOR APPROPRIATION DOCT	426.4	50,000
IDAHO PROSPERITY FUND	426.4	18,500
IDAHO REPUBLICAN PARTY	426.4	750
IDAHO STATE SOCIETY	426.4	10,638
IDAHO STATE UNIVERSITY	426.4	500
IDAHO WATER USERS ASSOCIA	426.4	1,700
IMPACT INCORPORATED	426.4	240
JANICE MCGEACHIN	426.4	500
JEFF THOMPSON FOR STATE REPRES	426.4	500
JIM HAMMOND FOR STATE SENATE	426.4	1,000
JOE PALMER FOR STATE REPRESENT	426.4	500
JOHN GOEDDE FOR STATE SENATE	426.4	1,000
JOHN MCGEE FOR STATE SENATE	426.4	1,000
JOHN RUSCHE FOR STATE REPRESEN	426.4	1,000
JOHN VANDERWOUDE FOR REPRESENT	426.4	500
JUDY BOYLE FOR STATE REPRESENT	426.4	500
KATHLEEN SIMS FOR STATE REPRES	426.4	500
KEN ROBERTS FOR STATE REPRESEN	426.4	500
KEVIN CAMERON FOR OREGON	426.4	1,000
KNOW IDAHO, INC	426.4	300
LARRY GEORGE FOR STATE SENATE	426.4	300
LENORE BARRETT FOR STATE	426.4	500
LITTLE GEM FUND	426.4	1,000
LYNN M LUKER FOR STATE REPRESE	426.4	500
MALMEN, JEFFREY L	426.4	555,921
MARC GIBBS FOR STATE REPRESENT	426.4	500
MARTIN, FRANCES J	426.4	3,090
MATT WAND FOR EAST COUNTY	426.4	300
MAX BLACK FOR STATE	426.4	500
MELINDA SMYSER FOR STATE SENAT	426.4	1,000
MIKE MOYLE FOR STATE REPRESENT	426.4	1,000
MIKE SCHAUFLER FOR STATE REP H	426.4	300
MISCELLANEOUS POLITICAL CONTRIBUTIONS	426.4	41,635
MITCH TORYANSKI FOR SENATE	426.4	1,000
		$ 1,130,272

POLITICAL CONTRIBUTIONS

INSTRUCTIONS: List all payments or contributions to persons and organizations for the purpose of aiding or defeating any measure before the people or to promote or prevent the enactment of any national, state, district or municipal legislation. The purpose of all contributions or payments should be clearly explained.
Report whole dollars only. Provide a total for each account and a grand total.

Description	Account Charged	Amount
MONTANA TAXPAYERS ASSOCIATION	426.4	$ 100
MONTY PEARCE FOR STATE SENATE	426.4	1,000
NELSON COMMUNICATIONS ASSOC	426.4	2,000
OREGONIANS FOR BRIAN CLEM	426.4	200
OREGONIANS FOR FOOD AND SHELTE	426.4	1,500
OTTER FOR IDAHO	426.4	5,000
PATTI ANNE LODGE FOR	426.4	1,000
PETE NIELSEN FOR STATE REPRESE	426.4	500
REED DEMORDAUNT FOR STATE REPR	426.4	500
RUSSELL FULCHER FOR STATE SENA	426.4	1,000
SCOTT BEDKE FOR STATE REPRESEN	426.4	1,000
SENATE REPUBLICAN PAC	426.4	600
TOM LOERTSCHER FOR STATE REPRE	426.4	500
WAYNE KRIEGER FOR	426.4	300
WELLS FARGO ACCRUAL	426.4	6,838
WESTERN GOVERNORS' ASSOCIATION	426.4	15,000
WESTERN STATES WATER COUNCIL	426.4	500
		$ 1,167,810

INSTRUCTIONS: List all donations made by the utility during the year and the accounts charged (Items less than $1,000 may be consolidated by category stating the number of organizations included). Give the name city and state of each organization to whom a donation has been made. Group donations under headings such as:

1. Contributions to and memberships in charitable organizations
2. Organizations of the utility industry
3. Technical and professional organizations
4. Commercial and trade organizations
5. All other organizations and kinds of donations and contributions

List donations by type and group by the accounts charged. Report whole dollars only. Provide a total for each group of donations.

Description	Account Number	Total Amount	Amount Assigned to Oregon
CONTRIBUTIONS TO AND MEMBERSHIPS IN: CHARITABLE ORGANIZATIONS			
2 LB BITE SIZED OWYH	426.1	1,908	None
4-H LIVESTOCK SALE	426.1	2,050	"
BAKER COUNTY FAIR - HALFWAY	426.1	1,233	"
BAKER COUNTY FAIR BOARD	426.1	1,500	"
BOISE STATE UNIVERSITY	426.1	16,100	"
BOY SCOUTS OF AMERICA	426.1	1,700	"
BOYS AND GIRLS CLUB	426.1	1,000	"
BRIGHAM YOUNG UNIVERSITY	426.1	6,500	"
CANYON COUNTY	426.1	1,000	"
CANYON COUNTY FESTIVAL	426.1	1,663	"
COLLEGE OF IDAHO	426.1	7,000	"
COLLEGE OF SOUTHERN IDAHO	426.1	2,120	"
FESTIVAL OF TREES	426.1	1,425	"
GONZAGA UNIVERSITY	426.1	2,000	"
HAGERMAN CEMETARY DISTRICT	426.1	2,000	"
HAGERMAN LDS WARD	426.1	2,000	"
HAVERFORD COLLEGE	426.1	2,000	"
IDACORP	426.1	220,000	"
IDAHO GOVERNERS CUP	426.1	16,500	"
IDAHO STATE UNIVERSITY	426.1	10,350	"
IDAHO TECH CONNECT	426.1	1,000	"
LEWIS CLARK STATE COLLEGE	426.1	2,000	"
LINFIELD COLLEGE	426.1	2,000	"
LIONS CLUB	426.1	1,730	"
MISCELLANEOUS ITEMS UNDER $1000 (329)	426.1	71,590	"
MONTANA STATE UNIVERSITY BILLINGS	426.1	2,000	"
NORTHWEST NAZARENE UNIVERSITY	426.1	2,000	"
PORTNEUF GREENWAY FOUNDATION	426.1	1,000	"
PORTNEUF VALLEY PAINTFEST	426.1	1,100	"
ROSE ADVOCATES	426.1	1,500	"
ROTARY CLUB	426.1	4,250	"
SAGE COMMUNITY RESOURCES	426.1	1,000	"
SALVATION ARMY	426.1	21,462	"
SEATTLE PACIFIC UNIVERSITY	426.1	2,000	"
SHRINER HOSPITALS FOR CHILDREN	426.1	1,000	"
SIERRA CLUB PGE SETTLEMENT	426.1	250,000	"
TEXAS A & M UNIVERSITY	426.1	1,000	
TREASURE VALLEY COMMUNITY COLLEGE	426.1	4,300	

INSTRUCTIONS: List all donations made by the utility during the year and the accounts charged (Items less than $1,000 may be consolidated by category stating the number of organizations included). Give the name city and state of each organization to whom a donation has been made. Group donations under headings such as:

1. Contributions to and memberships in charitable organizations
2. Organizations of the utility industry
3. Technical and professional organizations
4. Commercial and trade organizations
5. All other organizations and kinds of donations and contributions

List donations by type and group by the accounts charged. Report whole dollars only. Provide a total for each group of donations.

Description	Account Number	Total Amount	Amount Assigned to Oregon
U S NAVAL ACADEMY	426.1	1,000	
UNIVERSITY OF IDAHO	426.1	21,225	
UNIVERSITY OF MONTANA	426.1	1,500	
UNIVERSITY OF OREGON	426.1	2,000	
UNIVERSITY OF PENNSYLVANIA	426.1	1,000	
UNIVERSITY OF SOUTHERN CALIFOR	426.1	1,000	
UNIVERSITY OF UTAH	426.1	3,000	
UTAH STATE UNIVERSITY	426.1	2,000	
WASHINGTON STATE UNIVERSITY	426.1	2,000	
WESTMINSTER COLLEGE	426.1	2,000	
YMCA,BAKER FAMILY	426.1	1,000	
ZBOROWSKI, DE	426.1	1,913	
SUBTOTAL		710,618	
COMMERCIAL AND TRADE ORGANIZATIONS:			
CHAMBER OF COMMERCE	426.1	$ 8,100	None
			"
SUBTOTAL		8,100	"
TOTAL 426.1		718,718	

DONATIONS OR PAYMENTS FOR SERVICES RENDERED BY PERSONS OTHER THAN EMPLOYEES AND CHARGED TO OREGON OPERATING ACCOUNTS

1. Report for each service rendered (including materials furnished incidental to the service which are impracticable of separation) by recipient and in total the aggregate of all payments made during the year where the aggregate of all such payments to a recipient was $25,000 or more including fees, retainers, commissions, gifts, contributions, assessments, bonuses, subscriptions, allowances for expenses or any other form of payments for services or as donations (except rents for property, taxes, utility services, traffic settlements, amounts paid for general services and licenses, accurals paid to trustees of pension and other employee benefit funds, and amounts paid for construction or maintenance of plant to persons other than affiliates) to any one corporation, institution, association, firm, partnership, committee, or person (not an employee of the respondent). Indicate by an asterisk in column (c) each item that includes payments for materials furnished incidental to the service performed. Payments to a recipient by two or more companies within a single system under a cost sharing or other joint arrangement shall be considered a single item for reporting in this schedule and shall be shown in the report of the principal company in the joint arrangement (as measured by gross operating revenues) with references thereto in the reports of the other system companies in the joint arrangement.
2. If more convenient, this schedule may be filled out for a group of companies considered as one system and shown only in the report of the principal company in the system, with references thereto in the reports of the other companies.

	Name of Recipient (a)	Nature of Service (b)	Amount of Payment Allocated to Oregon (c)
1	ADM ASSOCIATES INC	Energy Efficiency Services	$ 2,241
2	AGREE TECHNOLOGIES AND SOLUTION	Energy Efficiency Services	7,307
3	BARKER, ROSHOLT & SIMPSON LLP	Legal Services	21,912
4	BERGLES LAW LLC	Legal Services	3,319
5	BRASSEY, WETHRELL, & CRAWFORD,	Legal Services	1,965
6	BRENNEMAN, JOHN	Lobby Services	3,376
7	BRIGHAM YOUNG UNIVERSITY	Environmental Services	1,264
8	BROWNSTEIN HYATT FARBER SCHREC	Legal Services	9,047
9	CADMUS GROUP INC, THE	Consulting Services	2,539
10	DAVID EVANS AND ASSOCIATES	Consulting Services	1,225
11	DAVIS WRIGHT TREMAINE LLP	Legal Services	23,598
12	DELOITTE & TOUCHE	Accounting Services	18,332
13	DESERT RESEARCH INSTITUTE	Environmental Services	3,698
14	DEWEY & LEBOEUF	Legal Services	4,069
15	DHI INC	Environmental Services	8,395
16	ECOS IQ	Consulting Services	1,833
17	ERISA LAW GROUP PA	Legal Services	2,507
18	EVERGREEN CONSULTING GROUP, LL	Consulting Services	7,212
19	FEHRN, BRIAN	Meterologist Services	1,802
20	GANNETT FLEMING INC	Energy Efficiency Services	1,752
21	GARTNER GROUP	Computer Support Services	5,790
22	GIVENS PURSLEY LLP	Legal Services	1,671
23	GLAHE & ASSOCIATES INC	Environmental Services	1,665
24	GLOBAL ENERGY PARTNERS LLC	Environmental Services	2,231
25	GREENBERG TRAURIG LLP	Legal Services	4,104
26	HARDESTY, REBECCA	Environmental Services	3,680
27	HYQUAL	Environmental Services	9,288
28	IDE LAW & STRATEGY, PPLC	Legal Services	3,080
29	INTER-FLUVE, INC.	Environmental Services	6,969
30	IOWA INSTITUTE OF HYDRAULICS	Engineering Services	7,251
31	JONES AND SWARTZ PLLC	Legal Services	1,779
32	MCDOWELL RACKNER & GIBSON PC	Legal Services	44,792
33	MERRILL COMMUNICATIONS LLC	Consulting Services	1,228
34	MIRANDE, MICHAEL	Legal Services	3,190
35	NIELSEN GROUP INC, THE	Consulting Services	10,166
36	PAINE HAMBLEN LLP	Management Services	11,161
37	PARR BROWN GEE & LOVELESS INC	Legal Services	2,692
38	PERKINS COIE LLP	Legal Services	21,206
39	PORTLAND ENERGY CONSERVATION,	Environmental Services	5,407

DONATIONS OR PAYMENTS FOR SERVICES RENDERED BY PERSONS OTHER THAN EMPLOYEES
AND CHARGED TO OREGON OPERATING ACCOUNTS

1. Report for each service rendered (including materials furnished incidental to the service which are impracticable of separation) by recipient and in total the aggregate of all payments made during the year where the aggregate of all such payments to a recipient was $25,000 or more including fees, retainers, commissions, gifts, contributions, assessments, bonuses, subscriptions, allowances for expenses or any other form of payments for services or as donations (except rents for property, taxes, utility services, traffic settlements, amounts paid for general services and licenses, accurals paid to trustees of pension and other employee benefit funds, and amounts paid for construction or maintenance of plant to persons other than affiliates) to any one corporation, institution, association, firm, partnership, committee, or person (not an employee of the respondent). Indicate by an asterisk in column (c) each item that includes payments for materials furnished incidental to the service performed. Payments to a recipient by two or more companies within a single system under a cost sharing or other joint arrangement shall be considered a single item for reporting in this schedule and shall be shown in the report of the principal company in the joint arrangement (as measured by gross operating revenues) with references thereto in the reports of the other system companies in the joint arrangement.
2. If more convenient, this schedule may be filled out for a group of companies considered as one system and shown only in the report of the principal company in the system, with references thereto in the reports of the other companies.

	Name of Recipient (a)	Nature of Service (b)	Amount of Payment Allocated to Oregon (c)
40	RIVERSIDE TECHNOLOGY INC	Management Services	$ 2,604
41	SHARP & SMITH INC.	Engineering Services	6,635
42	SOFTWARE AG INC	Computer Support Services	4,382
43	SPATIAL NETWORK SOLUTIONS	Admin Training Services	1,327
44	STILLWATER SCIENCES	Environmental Services	2,144
45	STOEL RIVES LLP	Legal Services	8,791
46	SULLIVAN & CROMWELL	Management Services	5,976
47	TEKSYSTEMS	Staffing Services	1,777
48	UNIVERSITY CORPORATION FOR	Environmental Services	4,193
49	UNIVERSITY OF IDAHO	Environmental Services	17,458
50	URS CORPORATION	Environmental Services	1,445
51	UTAH STATE UNIVERSITY	Environmental Services	3,154
52	VAN NESS FELDMAN	Consulting Services	2,729
53	WEATHER MODIFICATION INC	Cloud Seeding Services	16,751
54	YTURRI& ROSE& BURNHAM& BENTZ	Legal Services	1,734
55			
56			
57			
58			
59			
60			
61			
62			
63			
64			
65			
66			
67			
68			
69			
70			
71			
72			
73			
74			
75			
76			
77			
78			
79			
80	TOTAL		$ 355,842.88

FORWARD

IDACORP

2011 Annual Report

To our fellow shareowners

At IDACORP, we have a legacy of building today for tomorrow's needs. And 2011 was a year in which financial, technological and infrastructure plans at our primary subsidiary — Idaho Power — came together to build for the long view. Our three-part strategy of responsible planning, responsible development and protection of resources, and responsible energy use means we are looking to the future while meeting today's energy needs. Much like in the 1950s when Idaho Power built the three-dam Hells Canyon hydroelectric complex, our work has always set the stage for today's success, as well as future growth. We are preparing for tomorrow for our customers, for our employees, and for you, our owners.

As part of our look forward, our company was active on many fronts during 2011. We continued construction of the Langley Gulch Power Plant and created our 2011 Integrated Resource Plan, our biennial 20-year planning document. We also pursued general rate cases in Idaho and Oregon — both of which concluded with collaborative settlements. And we made progress on our two large transmission projects, Boardman to Hemingway and Gateway West.

Specifically, we forged an agreement with the Bonneville Power Administration and PacifiCorp to jointly fund the environmental review and permitting of the 300-mile Boardman to Hemingway project. We continue to work jointly with PacifiCorp on permitting the proposed 1,150-mile Gateway West project, and reached a significant milestone this summer when the Bureau of Land Management issued the draft Environmental Impact Statement for the project. Both of these key projects will provide additional access to regional energy markets, increased flexibility to site future generation resources in southern Idaho, and improve reliability.

2011 was a good year financially, led by a strong third quarter, itself supported by momentum built in the first two quarters. The third quarter brought a change that allowed us to take advantage of benefits associated with Idaho Power's uniform capitalization tax method, which resulted in a welcomed outcome during a continued weak economic environment. The tax method change not only contributed to our bottom line, but resulted in $47 million in benefits for our customers through two regulatory sharing mechanisms. It's also important to acknowledge other factors that contributed to our excellent results, including effective rate initiatives, strong hydroelectric conditions, and increased sales volumes among most customer

Langley Gulch Power Plant

classes due to a cooler winter and warmer summer.

Our vision to be regarded as an exceptional utility continues to guide us. We continued to look out for the best interests of both our owners and our customers. One example is our request — and subsequent commission approval — to continue an agreement that has shown proven benefit to customers and owners, providing a revenue sharing opportunity for customers and earnings support for our company. This win-win will extend through 2014.

Total shareowner return on IDACORP stock in calendar year 2011 was more than 18 percent. And, looking forward, our Board of Directors increased the 2012 regular quarterly cash dividend to $0.33 per share from $0.30 per share, representing a 10 percent increase. On the customer side, our company was able to provide Idaho customers a rate reduction of more than $25 million on June 1, 2011, due to the combined effects of several regulatory mechanisms. To provide this benefit to customers in the current economy was positive on many fronts.

With the nearly 500,000 customers we serve, Idaho Power improved to the fourth-highest ranking in the West Midsize segment in the results of the 2011 J.D. Power and Associates Electric Utility Residential Customer Satisfaction Study. In this study, Idaho Power performed particularly well in Power Quality & Reliability, Price, Corporate Citizenship, Communication and Customer Service. Our company also tied for first place in the West Midsize segment in the J.D. Power and Associates 2012 Electric Utility Business Customer Satisfaction Study.

Enhancing our ability to serve customers was the successful completion of a three-year process to install approximately 500,000 "smart" electric meters for customers throughout our service area in 2011. The new meters are part of our

Advanced Metering Infrastructure (AMI) initiative and the overall Smart Grid program. These meters are digital, secure and easier for customers to read. Their functionality enables customers to have more information about their energy use, empowering them to better manage their consumption. The meters also allow our company to save on fuel and maintenance costs, as employees are no longer driving 1.6 million miles per year to read meters.

Additionally, *Intelligent Utility* magazine ranked IDACORP the sixth most intelligent utility in 2011, up from 10th place in 2010. With a score of 141.5, we are considered "Near Genius."

As we look at our accomplishments in 2011, we also look forward to 2012 and beyond. To that end, in November we announced leadership changes that reinforce the successful foundation we've already laid to build for future years.

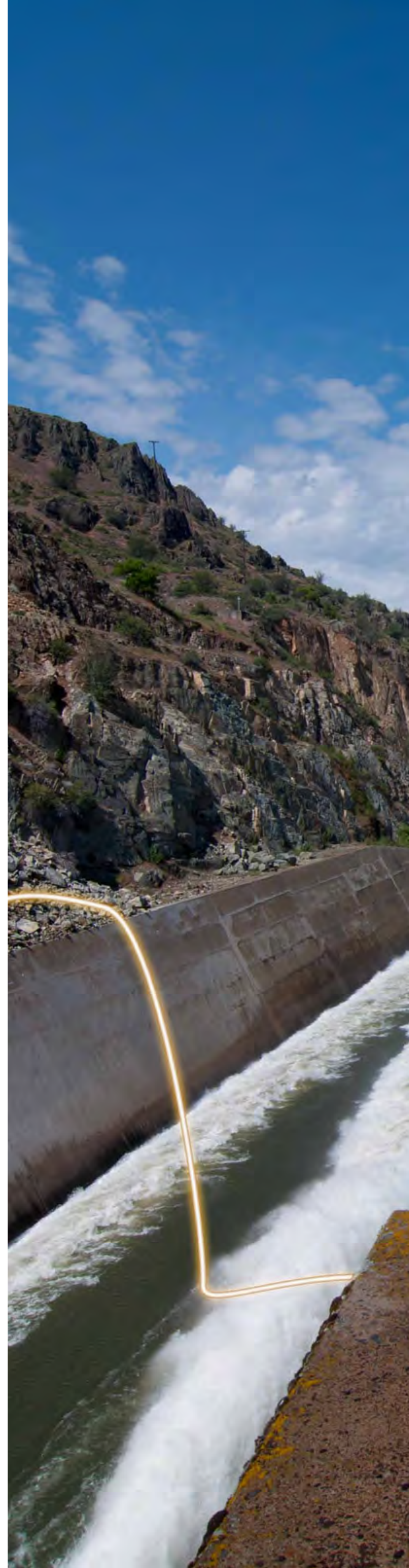
Beginning Jan. 1, 2012, Darrel Anderson assumed the role of President and Chief Financial Officer of Idaho Power, and will continue as Executive Vice President and Chief Financial Officer for IDACORP. Dan Minor was named Executive Vice President and Chief Operating Officer of Idaho Power. Steve Keen was promoted to Senior Vice President of Finance and Treasurer at Idaho Power.

These changes continue our legacy of strong leadership. Our entire leadership team continues to work hard to position Idaho Power and IDACORP for the future, while maintaining a connection to our history of success, and the people and communities we serve.

Finally, we couldn't have accomplished any of the past year's successes without the more than 2,000 dedicated men and women who make IDACORP run each and every day. We would like to extend a heartfelt "thank you" to them and to our Board of Directors for making 2011 a positive and prosperous year for our company. Here's to a successful 2012.

J. LaMont Keen, President & Chief Executive Officer

Gary Michael, Chairman of the Board



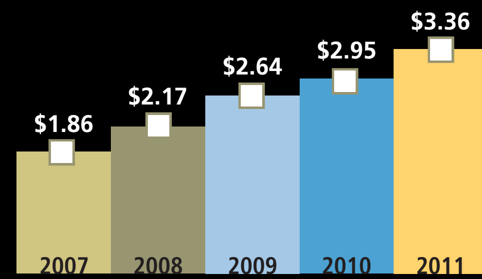
Oxbow Power Plant

2011 HIGHLIGHTS

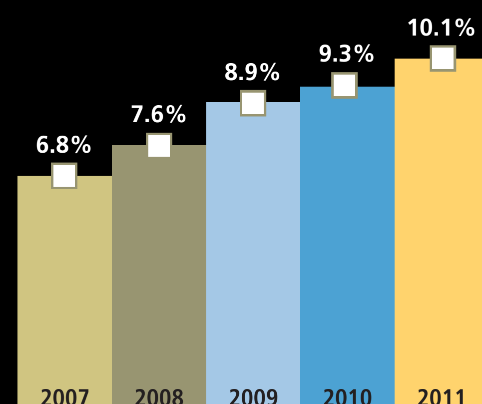
Thousands of Dollars, Except Per Share Amounts	2011	2010	% Change
Total Operating Revenues	$1,026,756	$1,036,029	<0.9>
Net Income	$166,693	$142,798	16.7
Earnings Per Diluted Common Share	$3.36	$2.95	13.9
Dividends Paid Per Common Share	$1.20	$1.20	--
Total Assets	$4,960,609	$4,676,055	6.1
Number of Employees (full-time)	2,058	2,032	1.3

Earnings Per Share (Diluted)

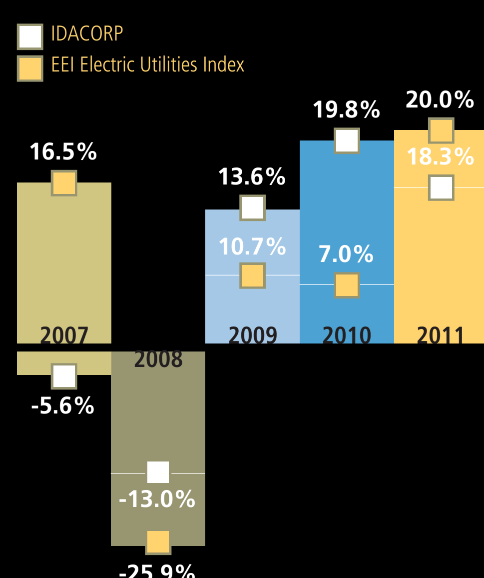
Current Annual Dividend $1.20



Return on Year-End Equity



Total Return



The Long View

IDACORP and its core business Idaho Power have taken "the long view" ever since our company was founded. Rather than peering around the next corner, reacting to outside pressures or resting on past achievements, we're looking down the road...and beyond. This has been a successful strategy ever since "back in the day," when our Swan Falls project first delivered energy to the mountain mining communities that were the engines of the economy.

We also take time to look back and learn from the past. Idaho Power is a company steeped in history and tradition. We have been powering lives by providing electricity for nearly a century, and will continue this legacy a hundred years into the future.

One reason we have successfully maintained our tradition of service is our three-part business strategy. Responsible planning, responsible development and protection of resources, and responsible energy use aren't just words at Idaho Power — they define the way we deliver electric service to the people who count on us every day.

We're planning for future growth and the eventual rebound of the economy. We're diversifying our resource portfolio to include new baseload natural gas capacity, as well as renewables such as wind, solar and geothermal. We're diligently pursuing regulatory strategies that help keep rates low while providing a good return to our owners. And these are just a few of our key initiatives. We're constantly evolving and adapting on all fronts.

It's worth noting that Idaho Power employees are Idaho Power customers. We don't just work for our company — we live and play in and are part of the communities we serve. And we are committed to the prosperity of those communities and the characteristics that make them the unique places we are proud to call home. Today and tomorrow.

Swan Falls Power Plant

We have been powering lives by providing electricity for nearly a century, and will continue this legacy a hundred years into the future.

A Long Look at Resources

11

Integrated Resource Plan (IRP)

There's nearly a century of trust built up between Idaho Power and the nearly 500,000 customers we serve, and it's our duty to honor that trust. Across our entire business, we're planning for the safe, secure energy future our customers are counting on us to provide.

One way we do this is our IRP, a biennial planning document which looks 20 years into the future. It encompasses many forward-looking elements, including development of a portfolio of energy resources, identification of future power generation and transmission needs, a continued focus on adding responsible renewable resources, and offering programs that encourage customers to use electricity efficiently.

Building our energy future requires collaboration and input. The IRP planning process doesn't happen in a vacuum; we involve stakeholders from all aspects of our business and our service area. There are a multitude of voices engaged in the process, which makes our planning just that much stronger.

We've been putting together IRPs for 20 years, and it's impressive to see how they have evolved. Each update builds on the foundation of earlier resource plans, and each includes incremental adjustments due to changing forecasts of future events. For instance, our first IRP, in 1991, included a portfolio heavy in coal resources. The 2011 version has taken a turn to natural gas, additional transmission, and renewable resources. These changes are an appropriate response given our look into the future.

Langley Gulch Power Plant

Idaho Power's ability to evolve with the times is literally expanding through the construction of our Langley Gulch natural gas-fired power plant. The clean, quiet, highly efficient power plant is being built on nearly 140 acres of undeveloped rangeland in a rural area about 50 miles west of our corporate headquarters in Boise.

The project is within budget and on schedule. We expect to bring this newest resource online by July 1, 2012 — in time to meet customer demand for summer power.

We built Langley Gulch in lieu of pursuing additional coal-burning generation. Langley's combined-cycle

technology burns clean. That means a reduced carbon footprint — something our customers and our shareholders both appreciate and want.

As a baseload plant, the facility will be efficient and economical, and will run a great deal of the time. It also has the flexibility to vary output quickly to help integrate intermittent resources such as wind and solar.

Hydroelectric Generation

What began as a challenging water year — in part mitigated by good carryover storage — has improved in recent weeks thanks to the better-late-than-never start to winter. January and February storms in the service area brought much needed precipitation and snow pack accumulations in the mountains. However, we are still below normal in the Snake River basin.

Due largely to favorable water conditions, hydroelectric generation comprised 69 percent of Idaho Power's total system generation during 2011, compared to 51 percent during 2010. As of Feb. 22, 2012, Idaho Power expects hydroelectric generation during 2012 to be in the range of 7.5 to 9.5 million megawatt-

hours (MWh), compared to 10.9 million MWh in 2011 and 7.3 million MWh in 2010. Median annual hydroelectric generation is 8.6 million MWh.

Through our longstanding annual Power Cost Adjustment (PCA) mechanism, if power supply costs are above those anticipated, our Idaho customers pay 95 percent of the excess costs and the company absorbs the remaining 5 percent. This PCA "split," implemented in 2009, helps protect us from the whims of Mother Nature, smoothing out power supply cost volatility.

Renewables and PURPA

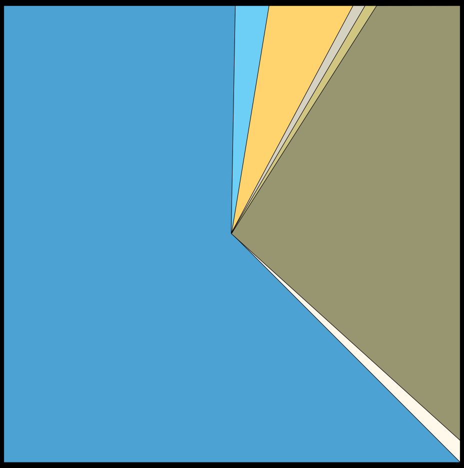
For nearly a century, Idaho Power has been committed to clean energy. Today about half of the energy in our portfolio is generated from hydro, wind, solar, biomass and geothermal. We are proud of our small carbon footprint and history of responsible energy that rivals that of any electric utility in the nation.

Over the past few years, renewable energy projects, especially wind projects, which qualify for higher rates under PURPA, or the Public Utility Regulatory Policies Act, have put an undue burden on the company and our customers. Over the next 10 years, customers may pay $850 million more than necessary for electricity that might not be needed. Because the cost is

borne by our customers, we are taking aggressive regulatory steps to address this imbalance.

Make no mistake — Idaho Power is a strong supporter of renewable energy. We always have been and will continue to be. We also believe that the addition of renewable resources needs to be accomplished responsibly, in a way that minimizes costs, and that does not impact our ability to provide reliable electric service to customers, every hour of every day. We know customers benefit from a diverse energy resource mix that can reliably provide electricity at a fair price. They always have, and always will.

2011 Resource Portfolio Fuel Mix*



Hydro 63.0%
Natural Gas 2.0%
Wind 5.5%
Waste 0.5%
Biomass 0.4%
Coal 28.1%
Other 0.6%

* Because Idaho Power sells (or does not own) the renewable energy certificates or "green tags" associated with certain projects in its resource portfolio, using the proceeds to benefit customers, we are not permitted to say the electricity from those projects is delivered to customers.

Building our energy future requires collaboration and input.

We were pleased to be able to share earnings with customers in 2011, and potentially again in 2012 and in the following two years as well.

The Long Regulatory View

Idaho General Rate Case (GRC) settlement

By design, regulatory strategy requires a long look forward. The future must be analyzed, based on the present, in order to prepare for change that we know will come. We must also collaborate with stakeholders and take into account their needs and perspective to ensure the best outcome. The people who drive our regulatory strategy practice this day in and day out, with an excellent track record of success.

In late December, the Idaho Public Utilities Commission issued an order in Idaho Power's 2011 GRC increasing base rates 4.19 percent, effective Jan. 1, 2012. This positive outcome was the result of a collaborative settlement reached with the company, the commission staff and customer groups. It provides our company a $34 million revenue increase, and a 7.86 percent authorized rate of return on rate base.

Idaho sharing settlement

The year 2011 also included realization of a $57 million income tax benefit for our company from a tax accounting method change. This contributed to the triggering of the sharing mechanism under our January 2010 Idaho settlement agreement, which provided that Idaho Power earnings over a 10.5 percent return on year-end equity in the Idaho jurisdiction are to be shared equally between Idaho customers and the company.

Also in the fourth quarter of 2011, we received a favorable commission decision regarding the continued availability of accumulated deferred investment tax credits. This gives the company return on equity/earnings-per-share support and helps position us for future success. It also allows us an opportunity to share earnings with customers now and in the future.

The sharing mechanism and settlement combined to provide $47 million in benefits to Idaho customers in 2011, while also reducing operating revenues for the period — a proven benefit to both customers and our company. And unlike previous settlement agreements, this one does not include a base rate moratorium. This gives us needed flexibility and allows us to continue positioning our company for success in 2012 and beyond.

We were pleased to be able to share earnings with customers in 2011, and potentially again in 2012 and in the following two years as well.

Long-Term Financial Stability

Economic development and new large loads

The availability of competitively-priced electric service is essential to a healthy economy and necessary to attract, retain and expand business and industry. This proved true once again in November, as New York-based Agro Farma chose Twin Falls, Idaho as home to their newest, multi-million-dollar processing plant for their Greek yogurt brand, Chobani. This new large load will help contribute to the economy of our state, creating jobs and contributing to customer growth. The plant is anticipated to bring 400 new jobs to our service area, and is scheduled to start production in 2012.

400 New jobs

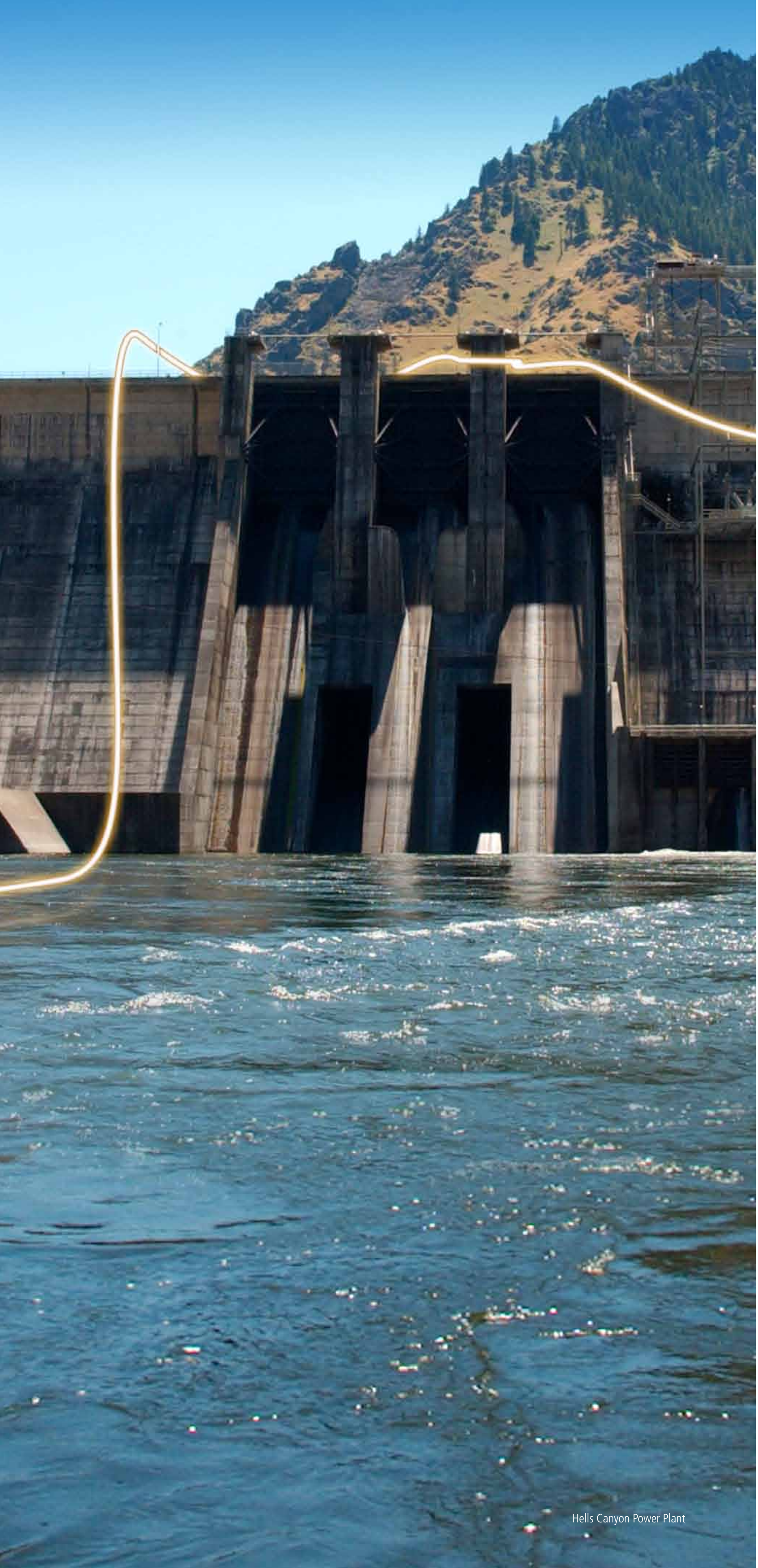
Liquidity

2011 was strong both financially and operationally. Financially, we recorded $3.36 in diluted annual earnings per share. This marks the fourth consecutive annual increase. IDACORP's cash flow from operations for 2011 was $310.2 million, an increase of $4.8 million from 2010 and a $25.8 million increase from 2009.

$3.36 diluted annual earnings per share

New five-year credit facilities at IDACORP and Idaho Power

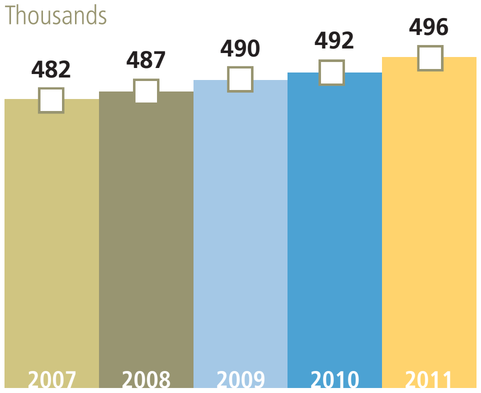
On Oct. 26, 2011, we executed new five-year credit agreements which increased the size of the IDACORP facility from $100 million to $125 million, but maintained the Idaho Power facility at $300 million. Commercial paper outstanding at IDACORP as of Dec. 31, 2011 was $54.2 million compared to $66.9 million at Dec. 31, 2010. Idaho Power had no commercial paper outstanding at either date.



Hells Canyon Power Plant

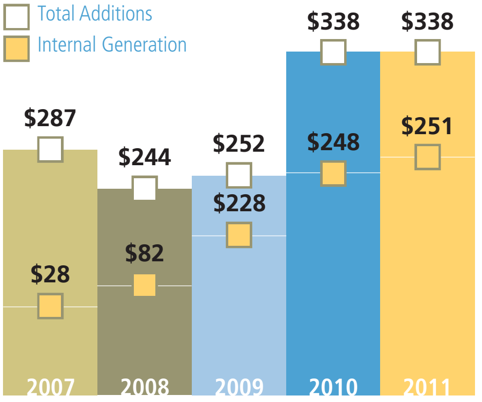
General Business Customers

Thousands



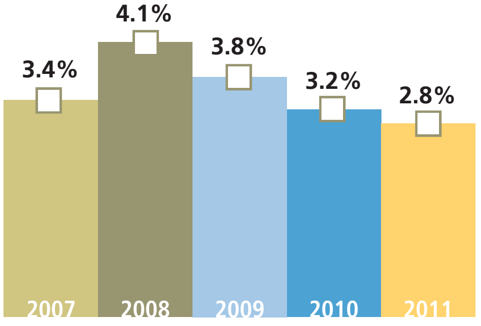
Additions to Property Plant and Equipment

Millions of dollars



Dividend Yield

At year-end



We have installed nearly

500,000

"**smart**" electric meters

Idaho Power transmission lines

Future Planning for the Long Term

Transmission projects

Idaho Power works each day to ensure our system is strong so power is reliable now and in the future. Our efforts to permit and build high-capacity transmission projects will ensure we have capacity and options available for economic development as the economy rebounds.

We have forged an agreement with the Bonneville Power Administration and PacifiCorp to jointly fund the environmental review and permitting of the 300-mile Boardman to Hemingway (B2H) project. We continue to work jointly with PacifiCorp on permitting the proposed 1,150-mile Gateway West project and reached a significant milestone this summer when the Bureau of Land Management issued the draft Environmental Impact Statement for the project. Both of these key projects will provide additional access to regional energy markets, increased flexibility to site future generation resources in southern Idaho, and improve reliability.

The B2H project will be essential to move electricity to and from the Pacific Northwest, and the Gateway West project will allow Idaho Power to site future generation resources in southern Idaho and deliver energy to customers. The partnerships help ensure the success of the projects and position us to move forward with construction once permits are secured.

Smart Grid

For Idaho Power, the Smart Grid represents energy innovation. Through our Smart Grid projects we'll reduce the time and impact of outages; strengthen the grid by limiting the effects of power line disturbances; and support integration of renewable energy into our resource portfolio. We're arming customers with the information they need to be wise energy consumers. We're using proven new technology to retrieve energy usage data, and taking actions that will improve electrical grid performance.

Advanced Metering Infrastructure (AMI)

The year 2011 brought the successful completion of our three-year AMI project. We have installed nearly 500,000 "smart" electric meters for customers throughout our service area. These new meters are the foundation of our ongoing Smart Grid program.

The Future of Stewardship

Sustainability at IDACORP

The IRP process, transmission projects, and our regulatory activities are just some of the ways IDACORP looks toward the future. But that's not all. Sustainability is a business operating approach that focuses on enhancing financial, environmental and societal stewardship on a daily basis. Specifically, sustainability at IDACORP promotes three "E"s in business operations:

- Enhanced operating efficiencies to reduce costs
- Enhanced long-term value for shareholders
- Enhanced relationships with stakeholders

Greenhouse gas emissions update

In service of our commitment to sustainability, Idaho Power is on track to meet its greenhouse gas (GHG) emissions reduction goal: reduce carbon dioxide (CO_2) emission intensity for 2010 to 2013 to 10 to 15 percent below 2005 CO_2 emission intensity. Idaho Power also remains committed to producing as much electricity as possible from hydropower for the benefit of customers and as a means of generating without producing GHG emissions.

Long Valley Operations Center

Sustainability is a business operating approach that focuses on enhancing financial, environmental and societal stewardship on a daily basis.

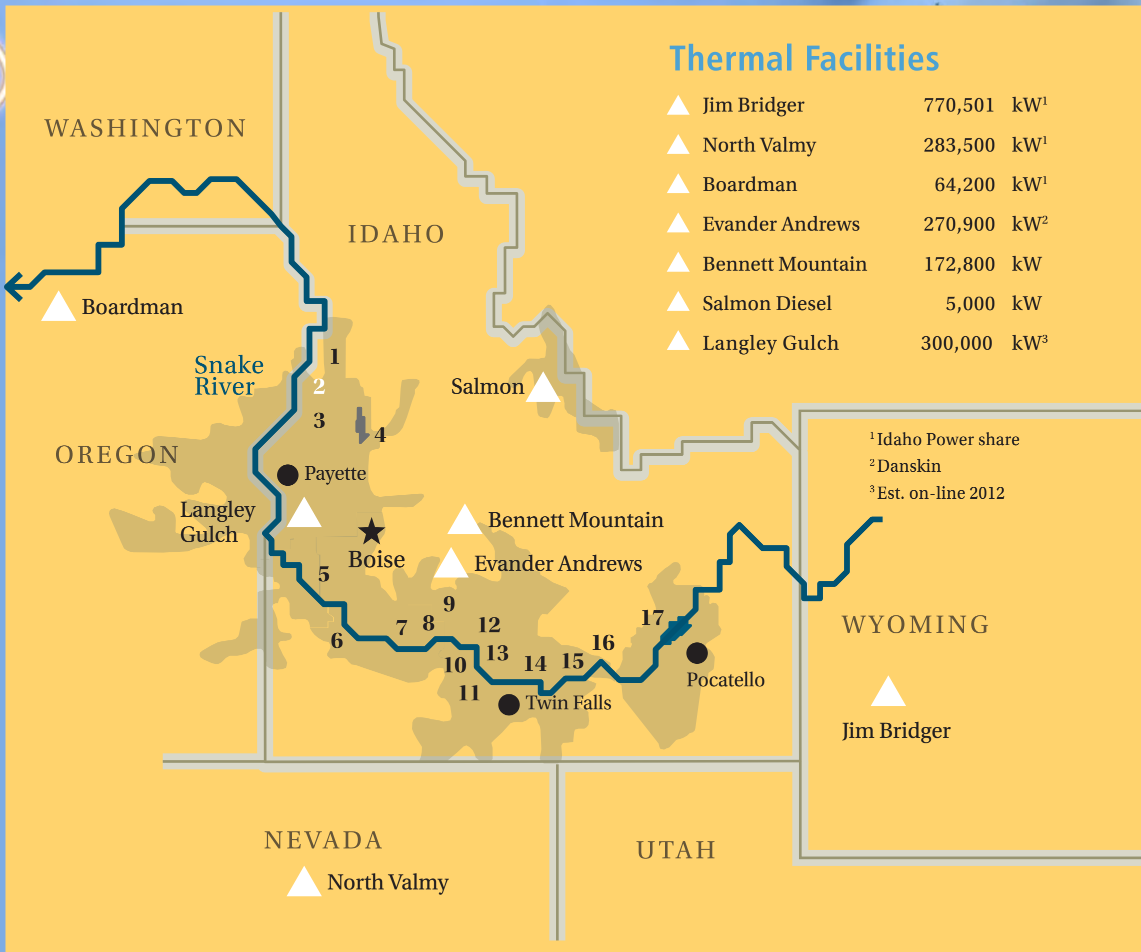
We are building a **financially strong**, stable company to meet the needs of our customers.

Looking Back, Moving Forward

Taking the long view means being future-focused and adaptable. It's the willingness and foresight to evolve and change as needed. To not just accept — but to embrace — the flexibility necessary to overcome the next challenge.

At IDACORP we are building a financially strong, stable company to meet the needs of our customers. We've done this for nearly 100 years. Our homes, communities, schools, farms and businesses have always needed our product, and we're at the ready to provide an energy present and an energy future that enables economic development while maintaining the comfort and security that are paramount to quality of life.

So, in partnership with you, our owners, we will continue our efforts to maintain our heritage, focus on present-day goals, and sustain momentum for a bright future. We will stay nimble; we will evolve; and we are confident. Together we will take the long view and continue building a responsible, sustainable energy future for many generations to come.



Thermal Facilities

Jim Bridger	770,501	kW[1]
North Valmy	283,500	kW[1]
Boardman	64,200	kW[1]
Evander Andrews	270,900	kW[2]
Bennett Mountain	172,800	kW
Salmon Diesel	5,000	kW
Langley Gulch	300,000	kW[3]

[1] Idaho Power share
[2] Danskin
[3] Est. on-line 2012

Shoshone Falls and power plant

IDACORP and Idaho Power Officers

IDACORP and Idaho Power

J. LaMont Keen (37)
President and Chief Executive Officer, IDACORP, Inc. and Chief Executive Officer, Idaho Power

Darrel T. Anderson (16)
Executive Vice President – Administrative Services and Chief Financial Officer, IDACORP, Inc. and President and Chief Financial Officer, Idaho Power

Rex Blackburn (4)
Senior Vice President and General Counsel, IDACORP, Inc. and Idaho Power

Patrick A. Harrington (26)
Corporate Secretary, IDACORP, Inc. and Idaho Power

Steven R. Keen (29)
Vice President – Finance and Treasurer, IDACORP, Inc. and Senior Vice President – Finance and Treasurer, Idaho Power

Jeffrey L. Malmen (4)
Vice President of Public Affairs, IDACORP, Inc. and Idaho Power

Daniel B. Minor (26)
Executive Vice President, IDACORP, Inc. and Executive Vice President and Chief Operating Officer, Idaho Power

Ken W. Petersen (13)
Corporate Controller and Chief Accounting Officer, IDACORP, Inc. and Idaho Power

Lori D. Smith (28)
Vice President and Chief Risk Officer, IDACORP, Inc. and Idaho Power

Idaho Power

Dennis C. Gribble (33)
Vice President and Chief Information Officer

Lisa A. Grow (24)
Senior Vice President of Power Supply

Warren Kline (38)
Vice President of Customer Operations

Luci K. McDonald (7)
Vice President of Human Resources and Corporate Services

N. Vern Porter (22)
Vice President of Delivery Engineering and Operations

Gregory W. Said (31)
Vice President of Regulatory Affairs

Naomi C. Shankel (11)
Vice President of Supply Chain

( ) years of service

Hydroelectric Facilities & Nameplate Capacities

1	Hells Canyon	391,500 kW
2	Oxbow	190,000 kW
3	Brownlee	585,400 kW
4	Cascade	12,420 kW
5	Swan Falls	27,170 kW
6	C.J. Strike	82,800 kW
7	Bliss	75,000 kW
8	Lower Malad	13,500 kW
9	Upper Malad	8,270 kW
10	Lower Salmon	60,000 kW
11	Upper Salmon	34,500 kW
12	Thousand Springs	8,800 kW
13	Clear Lake	2,500 kW
14	Shoshone Falls	12,500 kW
15	Twin Falls	52,897 kW
16	Milner	59,448 kW
17	American Falls	92,340 kW

Service Area

References

Dividend Payment Dates

For IDACORP, Inc. Common Stock quarterly on or about the 28th of February, and the 30th of May, August and November.

Transfer Agents/Registrar

For IDACORP, Inc. Common Stock
Wells Fargo Shareowner Services
161 N. Concord Exchange St.
South St. Paul, Minnesota 55075-1139
1-800-565-7890

Common Stock Information

Ticker symbol: IDA
Listed: New York Stock Exchange, 20 Broad St.
New York, New York 10005

Contact

Broker/Analyst Contact: Lawrence F. Spencer,
Director of Investor Relations
208-388-2664 Fax: 208-388-6916
Email: lspencer@idacorpinc.com

Shareowner Contact: 1-800-635-5406 Fax: 208-388-6955
Email: cshepard@idahopower.com
or barbsmith@idahopower.com

Corporate Headquarters

Website: www.idacorpinc.com
Mailing: P.O. Box 70, Boise, Idaho 83707-0070
Street: 1221 W. Idaho St., Boise, Idaho 83702-5627
Phone: 208-388-2200

SEC Form 10-K

The IDACORP, Inc. and Idaho Power Company combined Form 10-K has been filed with the Securities and Exchange Commission. The Form 10-K and this Annual Report to Shareholders also are available on our website at www.idacorpinc.com. This report is prepared for the information of shareholders of the company and is not to be transmitted, nor is it to be used by others in connection with any sale, offer for sale or solicitation of any offer to buy any securities.

Forward-Looking Statement

Please refer to IDACORP's and Idaho Power's Form 10-K for a description of the substantial risks and uncertainties related to the forward-looking statements included in this Annual Report.

IDACORP, Inc.—Boise, Idaho-based and formed in 1998—is a holding company comprised of Idaho Power Company, a regulated electric utility; IDACORP Financial, a holder of affordable housing projects and other real estate investments; and Ida-West Energy, an operator of small hydroelectric generation projects that satisfy the requirements of the Public Utility Regulatory Policies Act of 1978. IDACORP's origins lie with Idaho Power and operations beginning in 1916. Today, Idaho Power employs approximately 2,000 people to serve a 24,000-square-mile service area in southern Idaho and eastern Oregon. With 17 low-cost hydroelectric projects as the core of its generation portfolio, Idaho Power's nearly 500,000 residential, business and agricultural customers pay some of the nation's lowest prices for electricity. To learn more about Idaho Power or IDACORP, Inc., visit www.idahopower.com or www.idacorpinc.com.

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2011

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from .... to ....

Commission File Number	Exact name of registrants as specified in their charters, address of principal executive offices, zip code and telephone number	IRS Employer Identification Number
1-14465	**IDACORP, Inc.**	82-0505802
1-3198	**Idaho Power Company**	82-0130980
	1221 W. Idaho Street	
	Boise, ID 83702-5627	
	(208) 388-2200	

State of incorporation: Idaho

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:	Name of exchange on which registered
IDACORP, Inc.: Common Stock, without par value	New York Stock Exchange

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:
Idaho Power Company: Preferred Stock

Indicate by check mark whether the registrants are well-known seasoned issuers, as defined in Rule 405 of the Securities Act.

IDACORP, Inc.	Yes	(X)	No	( )	Idaho Power Company	Yes	( )	No	(X)

Indicate by check mark if the registrants are not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

IDACORP, Inc.	Yes	( )	No	(X)	Idaho Power Company	Yes	( )	No	(X)

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes (X) No ( )

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web sites, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files).

IDACORP, Inc.	Yes	(X)	No	( )	Idaho Power Company	Yes	(X)	No	( )

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. (X)

Indicate by check mark whether the registrants are large accelerated filers, accelerated filers, non-accelerated filers, or smaller reporting companies.

IDACORP, Inc.:

Large accelerated filer	(X)	Accelerated filer	( )	Non-accelerated filer	( )	Smaller reporting company	( )

Idaho Power Company:

Large accelerated filer	( )	Accelerated filer	( )	Non-accelerated filer	(X)	Smaller reporting company	( )

Indicate by check mark whether the registrants are shell companies (as defined in Rule 12b-2 of the Act).

IDACORP, Inc.	Yes	( )	No	(X)	Idaho Power Company	Yes	( )	No	(X)

Aggregate market value of voting and non-voting common stock held by non-affiliates (June 30, 2011):

IDACORP, Inc.:	$ 1,941,836,645	Idaho Power Company:	None

Number of shares of common stock outstanding as of February 17, 2012:

IDACORP, Inc.:	49,947,098
Idaho Power Company:	39,150,812, all held by IDACORP, Inc.

Documents Incorporated by Reference:

Part III, Items 10 - 14	Portions of IDACORP, Inc.'s definitive proxy statement to be filed pursuant to Regulation 14A for the 2012 annual meeting of shareholders.

This combined Form 10-K represents separate filings by IDACORP, Inc. and Idaho Power Company. Information contained herein relating to an individual registrant is filed by that registrant on its own behalf. Idaho Power Company makes no representation as to the information relating to IDACORP, Inc.'s other operations.

Idaho Power Company meets the conditions set forth in General Instruction (I)(1)(a) and (b) of Form 10-K and is therefore filing this Form with the reduced disclosure format.

COMMONLY USED TERMS

The following select abbreviations, terms, or acronyms are found in multiple locations within this report:

ADITC	-	Accumulated Deferred Investment Tax Credits
AFUDC	-	Allowance for Funds Used During Construction
AMI	-	Advanced Metering Infrastructure
aMW	-	Average Megawatts
APCU	-	Annual Power Cost Update
BCC	-	Bridger Coal Company, a joint venture of IERCo
BLM	-	U.S. Bureau of Land Management
BPA	-	Bonneville Power Administration
CAA	-	Clean Air Act
CAMP	-	Comprehensive Aquifer Management Plan
CO_2	-	Carbon Dioxide
CWA	-	Clean Water Act
DEIS	-	Draft Environmental Impact Statement
DSM	-	Demand-Side Management
DSR	-	Demand-Side Resources
EGUs	-	Electric Utility Steam Generating Units
EIS	-	Environmental Impact Statement
EPA	-	U.S. Environmental Protection Agency
EPS	-	Earnings Per Share
ESA	-	Endangered Species Act
FASB	-	Financial Accounting Standards Board
FCA	-	Fixed Cost Adjustment Mechanism
FERC	-	Federal Energy Regulatory Commission
FPA	-	Federal Power Act
GAAP	-	Generally Accepted Accounting Principles
GHG	-	Greenhouse Gas
HCC	-	Hells Canyon Complex
Ida-West	-	Ida-West Energy, a subsidiary of IDACORP, Inc.
Idaho ROE	-	Idaho-jurisdiction return on year-end equity
IE	-	IDACORP Energy, a subsidiary of IDACORP, Inc.
IERCo	-	Idaho Energy Resources Co., a subsidiary of Idaho Power Company
IFS	-	IDACORP Financial Services, a subsidiary of IDACORP, Inc.
IPUC	-	Idaho Public Utilities Commission
IRP	-	Integrated Resource Plan
IRS	-	U.S. Internal Revenue Service
kW	-	Kilowatt
LCAR	-	Load Change Adjustment Rate
MD&A	-	Management's Discussion and Analysis of Financial Condition and Results of Operations
MW	-	Megawatt
MWh	-	Megawatt-hour
NOx	-	Nitrous Oxide
NSPS	-	New Source Performance Standards
O&M	-	Operations and Maintenance
OATT	-	Open Access Transmission Tariff
OPUC	-	Oregon Public Utility Commission
PCA	-	Power Cost Adjustment
PCAM	-	Power Cost Adjustment Mechanism
PURPA	-	Public Utility Regulatory Policies Act of 1978
REC	-	Renewable Energy Certificate
RES	-	Renewable Energy Standard
RPS	-	Renewable Portfolio Standard
SEC	-	U.S. Securities and Exchange Commission
SO_2	-	Sulfur Dioxide
USBR	-	U.S. Bureau of Reclamation
Valmy	-	North Valmy Steam Electric Generating Plant
VIEs	-	Variable Interest Entities

TABLE OF CONTENTS

*Except as indicated in Items 12 and 14, IDACORP, Inc. information is incorporated by reference to IDACORP, Inc.'s definitive proxy statement for the 2012 annual meeting of shareholders.

SAFE HARBOR STATEMENT

This Annual Report on Form 10-K contains "forward-looking statements" intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995. Forward-looking statements should be read with the cautionary statements and important factors included in this Form 10-K at Part I, Item 1A - "Risk Factors" and in Part II, Item 7 - "Management's Discussion and Analysis of Financial Condition and Results of Operations" (including under the heading "Forward-Looking Statements"). Forward-looking statements are all statements other than statements of historical fact, including, without limitation, those that are identified by the use of the words "anticipates," "believes," "estimates," "expects," "intends," "plans," "targets," "predicts," "projects," "may result," "may continue," or similar expressions.

PART I
ITEM 1. BUSINESS

OVERVIEW

IDACORP, Inc. (IDACORP) is a holding company incorporated in 1998 under the laws of the state of Idaho, and its principal operating subsidiary is Idaho Power Company (Idaho Power). IDACORP is subject to the provisions of the Public Utility Holding Company Act of 2005, which provides access to books and records to the Federal Energy Regulatory Commission (FERC) and state utility regulatory commissions and imposes record retention and reporting requirements on IDACORP.

Idaho Power was incorporated under the laws of the state of Idaho in 1989 as successor to a Maine corporation organized in 1915. Idaho Power is an electric utility engaged in the generation, transmission, distribution, sale, and purchase of electric energy and is regulated by the FERC and the state regulatory commissions of Idaho and Oregon. Idaho Power is the parent of Idaho Energy Resources Co. (IERCo), a joint venturer in Bridger Coal Company (BCC), which mines and supplies coal to the Jim Bridger generating plant owned in part by Idaho Power.

IDACORP's other subsidiaries include IDACORP Financial Services, Inc. (IFS), an investor in affordable housing and other real estate investments; Ida-West Energy Company (Ida-West), an operator of small hydroelectric generation projects that satisfy the requirements of the Public Utility Regulatory Policies Act of 1978 (PURPA); and IDACORP Energy (IE), a marketer of energy commodities that wound down operations in 2003.

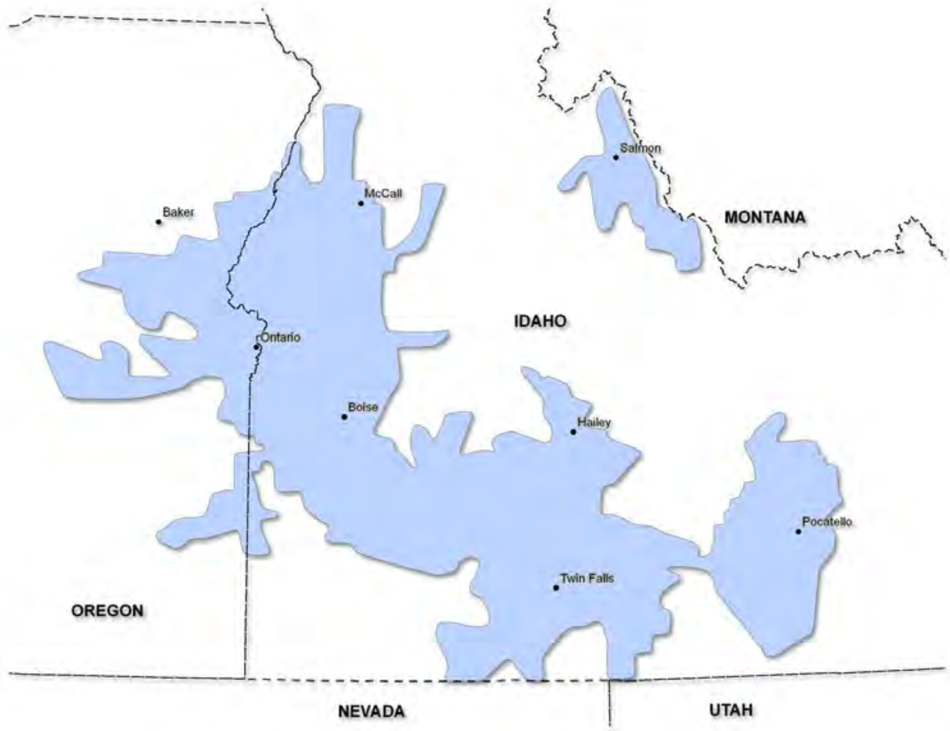
Idaho Power is IDACORP's only reportable business segment, contributing 99 percent of IDACORP's net income in 2011. Segment data is presented in Note 17 – "Segment Information" to the consolidated financial statements included in this report. As of December 31, 2011, IDACORP had 2,058 full-time employees, 2,046 of whom were employed by Idaho Power, and 23 part-time employees, 22 of whom were employed by Idaho Power.

IDACORP and Idaho Power make available free of charge on their websites their Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and all amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the U.S. Securities Exchange Act of 1934 as soon as reasonably practicable after the reports are electronically filed with or furnished to the U.S. Securities and Exchange Commission (SEC). IDACORP's website is *www.idacorpinc.com* and can also be accessed through a link to the IDACORP website on the Idaho Power website at *www.idahopower.com.* The contents of the above-referenced website addresses are not part of this Annual Report on Form 10-K. Reports, proxy and information statements, and other information regarding IDACORP and Idaho Power may also be obtained directly from the SEC's website, *www.sec.gov*, or from the SEC's Public Reference Room at 100 F Street, NE, Washington, D.C. 20549.

IDACORP's and Idaho Power's principal executive offices are located at 1221 W. Idaho Street, Boise, Idaho 83702, and the telephone number is (208) 388-2200.

UTILITY OPERATIONS

Idaho Power's service territory covers approximately 24,000 square miles in southern Idaho and eastern Oregon, with an estimated population of one million. Idaho Power holds franchises, typically in the form of right-of-way arrangements, in 71 cities in Idaho and nine cities in Oregon and holds certificates from the respective public utility regulatory authorities to serve all or a portion of 25 counties in Idaho and three counties in Oregon. As of December 31, 2011, Idaho Power supplied electric energy to approximately 496,000 general business customers. Idaho Power's principal commercial and industrial customers are involved in food processing, electronics and general manufacturing, agriculture, forest products, beet sugar refining, and winter recreation. Idaho Power's service territory is illustrated on the following page.



Weather, customer demand, and economic conditions impact electricity sales and costs and, therefore, utility revenues are not earned and associated expenses are not incurred evenly during the year. Extreme temperatures increase sales to customers who use electricity for cooling and heating, and moderate temperatures decrease sales. Increased precipitation levels during the agricultural growing season reduce electricity sales to customers who use electricity to operate irrigation pumps. Idaho Power's retail energy sales typically peak during the summer irrigation and cooling season, with a lower peak in the winter that generally results from demand for electric power for heating purposes.

Electric utilities have historically been recognized as natural monopolies and have operated in a highly regulated environment in which they have an obligation to provide electric service to their customers in return for an exclusive franchise within their service territory with an opportunity to earn a regulated rate of return. Idaho Power is under the retail jurisdiction (as to rates, service, accounting, and other general matters of utility operation) of the Idaho Public Utilities Commission (IPUC) and the Oregon Public Utility Commission (OPUC), and as a regulated electric utility Idaho Power is generally not subject to retail competition. Idaho Power is also under the jurisdiction of the IPUC, the OPUC, and the Public Service Commission of Wyoming as to the issuance of debt and equity securities. Further, the FERC has jurisdiction over, among other items, Idaho Power's transmission and wholesale sales of electricity, hydroelectric relicensing, and system reliability.

General Business Strategy

IDACORP's business strategy emphasizes Idaho Power as IDACORP's core business. Idaho Power has a three-part strategy of responsible planning, responsible development and protection of resources, and responsible energy use to ensure adequate energy supplies. Idaho Power continuously evaluates and refines its business strategy to ensure coordination among and integration of all functional areas of the company. Idaho Power's business strategy seeks to balance the interests of owners, customers, employees, and other stakeholders while maintaining the company's financial stability and flexibility. The strategy includes:

- ***Responsible Planning***: Idaho Power's planning process is intended to ensure adequate generation and transmission resources to meet anticipated population growth and increasing electricity demand. This planning process integrates Idaho Power's regulatory strategy and financial planning, including the consideration of regional economic development in the communities Idaho Power serves.

- ***Responsible Development and Protection of Resources***: Idaho Power's business strategy includes the development and protection of generation, transmission, distribution, and associated infrastructure, and stewardship of the natural resources Idaho Power and the communities it serves depend upon. Additionally, the strategy considers workforce planning and employee development and retention related to these strategic elements.

- ***Responsible Energy Use***: Idaho Power's business strategy includes energy efficiency and demand response programs and preparation for potential carbon and renewable portfolio standards (RPS) legislation. The strategy also includes targeted reductions relating to carbon emission intensity and public reporting of these reductions.

Rates and Revenues

***Retail*:** Idaho Power periodically evaluates the need to seek changes to its retail electricity price structure to cover its operating costs and provide a reasonable rate of return. Idaho Power uses general rate cases, power cost adjustment (PCA) mechanisms, a fixed cost adjustment (FCA) mechanism, a pension balancing account, and subject-specific filings to recover its costs of providing service and to earn a return on investment.

Retail prices are determined through formal ratemaking proceedings that generally include testimony by participating parties, data requests, public hearings, and the issuance of a final order. Participants in these proceedings, which are conducted under established procedural schedules, include Idaho Power, the IPUC or OPUC, and other interested parties. The IPUC and OPUC are required to ensure that the prices and terms of service are fair, non-discriminatory, and provide Idaho Power an opportunity to recover its costs and earn a fair return on investment. In addition to general rate case filings, ratemaking proceedings can involve charges or credits related to specific costs, programs, or activities, as well as the recovery or refund of deferred amounts recorded pursuant to specific authorization from the IPUC or OPUC. Deferred amounts are generally collected from, or refunded to, retail customers through the use of supplemental tariffs.

For additional information on regulatory matters, including significant rate cases and proceedings, see the “Regulatory Matters” section of Part II, Item 7 – “Management’s Discussion and Analysis of Financial Condition and Results of Operations” (MD&A) and Note 3 – “Regulatory Matters” to the consolidated financial statements included in this report.

Developments in 2011 with Special Customer Electric Service Agreements: Idaho Power is authorized to enter into special electric service arrangements with customers that have an aggregate power requirement that exceeds 20 megawatts (MW). Notable recent developments with respect to one of those arrangements are described below.

In March 2009, the IPUC approved a September 2008 electric service agreement between Idaho Power and Hoku Materials, Inc. (Hoku), to provide electric service to Hoku’s polysilicon production facility being constructed in Pocatello, Idaho. The initial term of the agreement is four years beginning December 1, 2009, with a maximum demand obligation during the initial term of 82 MW. Hoku was still not taking significant service as of December 31, 2011. In December 2011, Idaho Power sent to Hoku a notice of termination of service pursuant to IPUC rules to terminate service as a result of an overdue invoice for electric service. On January 9, 2012, Hoku filed a petition with the IPUC alleging that its contract with Idaho Power was contrary to the public interest and requested that the IPUC reform the contract and sought reparations for previously paid amounts under the electric service agreement. On January 13, 2012, the IPUC ordered Idaho Power and Hoku to enter into negotiations to seek settlement of Hoku's petition. On February 17, 2012, Idaho Power, Hoku, and the IPUC Staff filed with the IPUC a settlement stipulation that would amend the electric service agreement. The stipulation provides for a minimum monthly charge of $0.8 million (compared to the existing minimum monthly charge of approximately $2 million) from January 2012 to July 2013 and the establishment of a balancing mechanism that will track and accrue (up to a maximum balance of approximately $16.5 million) on a monthly basis the difference between (a) the first block minimum energy charges (excluding demand charges) under the existing agreement and (b) the modified minimum billed energy charge (excluding demand charges) under the settlement stipulation. In January 2014, Idaho Power will begin invoicing Hoku for, in addition to applicable demand and energy charges, recovery of the deferred amount over a 12 month period, one-twelfth per month. Further, the stipulation provides that Hoku will pay to Idaho Power $2.0 million upon IPUC approval of the stipulation out of existing funds on deposit with Idaho Power, and $0.1 million per month in cash for 18 months commencing with its January 2012 invoice. The stipulation also extends the term of the electric service agreement through December 1, 2014. During the final year of the agreement, Hoku will pay embedded-cost based rates for service. Hoku agrees in the stipulation to cap its monthly power demand during the January 2012 to July 2013 deferral period to 20 MW, with the option to increase usage to 82 MW following a notice period and payment of applicable deposits. In the event Hoku uses more than 20 MW of energy in any given month, Hoku will be required to pay the minimum billed energy charge amounts set forth in the existing electric service agreement.

Wholesale: As a public utility under Part II of the Federal Power Act (FPA), Idaho Power has authority to charge market-based rates for wholesale energy sales under its FERC tariff and to provide transmission services under its Open Access Transmission Tariff (OATT). Idaho Power’s OATT is revised each year based on financial and operational data Idaho Power files annually with the FERC in its Form 1. The Energy Policy Act of 2005 granted the FERC increased statutory authority to implement mandatory transmission and network reliability standards, as well as enhanced oversight of power and transmission markets, including protection against market manipulation. These mandatory transmission and reliability standards, which are applicable to Idaho Power, were developed by the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC), which has responsibility for compliance and enforcement of transmission and reliability standards.

Idaho Power has one low-volume wholesale reserve sales contract, with United Materials of Great Falls, Inc. The agreement requires Idaho Power to carry energy reserves in association with an energy sales agreement between Idaho Power and United Materials from the Horseshoe Bend Wind Farm located in Montana. The term of the agreement runs seasonally through May 2013. Idaho Power had one firm wholesale power sales contract with Raft River Electric Cooperative for up to 15 MW, which expired in September 2011.

Idaho Power participates in the wholesale energy market by buying power to help meet load demands and selling power that is in excess of load demands. Idaho Power's market activities are guided by a risk management policy and frequently updated operating plans, which are influenced by customer load, market prices, generating costs, and availability of generating resources. Some of Idaho Power's hydroelectric generation facilities are operated to optimize the water that is available by choosing when to run hydroelectric generation units and when to store water in reservoirs. These decisions affect the timing and volumes of market purchases and market sales. Even in below-normal water years, there are opportunities to vary water usage to maximize generation unit efficiency, capture marketplace economic benefits, and meet load demand. Wholesale energy market prices and compliance factors, such as allowable river stage elevation changes and flood control requirements, influence these dispatch decisions.

Energy Sales: The table below presents Idaho Power's revenues and energy use by customer type for the last three years. Approximately 95 percent of Idaho Power's general business revenue comes from customers located in Idaho, with the remainder coming from customers located in Oregon. Idaho Power's operations are discussed further in Part II, Item 7 - "MD&A – Results of Operations - Utility Operations."

	Year Ended December 31,		
	2011	**2010**	**2009**
Revenues (thousands of dollars)			
Residential	$ 405,982	$ 400,607	$ 409,479
Commercial	220,962	231,440	232,816
Industrial	140,701	138,394	141,530
Irrigation	104,635	110,555	109,655
Provision for sharing	(27,099)	—	—
Deferred revenue related to Hells Canyon Complex relicensing AFUDC	(10,636)	(10,625)	(9,715)
Total general business	834,545	870,371	883,765
Off-system sales	101,602	78,133	94,373
Other	86,581	84,548	67,858
Total	$ 1,022,728	$ 1,033,052	$ 1,045,996
Energy use (thousands of MWh)			
Residential	5,146	4,967	5,300
Commercial	3,815	3,763	3,858
Industrial	3,100	3,076	3,140
Irrigation	1,673	1,707	1,650
Total general business	13,734	13,513	13,948
Off-system sales	3,635	1,982	2,836
Total	17,369	15,495	16,784

Power Supply

Idaho Power primarily relies on company-owned hydroelectric, coal, and gas-fired generation facilities and long-term power purchase agreements to supply the energy needed to serve customers. Idaho Power's annual hydroelectric generation varies depending on water conditions in the Snake River. Market purchases and sales are used to balance supply and demand throughout the year. Idaho Power's generating plants and their capacities are listed in Part I, Item 2 - "Properties."

Weather, load demand, and economic conditions impact power supply costs. Drought conditions and increased peak load demand cause a greater reliance on potentially more expensive energy sources to meet load requirements. Conversely, favorable hydroelectric generation conditions increase production at Idaho Power's hydroelectric generating facilities and reduce the need for thermal generation and purchased power. Economic conditions can affect the market price of natural gas and coal, which may impact fuel expense and market prices for purchased power.

Idaho Power's system is dual peaking, with the larger peak demand occurring in the summer. The all-time system peak demand is 3,214 MW, set on June 30, 2008, and the all-time winter peak demand is 2,527 MW, set on December 10, 2009. During these and other similarly heavy load periods Idaho Power's system is fully committed to serve load and meet required operating reserves. During 2011, the largest peak demand was 2,973 MW, set on July 6, 2011. The following table presents Idaho Power's total power supply for the last three years:

	MWh			Percent of Total Generation		
	2011	**2010**	**2009**	**2011**	**2010**	**2009**
	(thousands of MWh)					
Hydroelectric plants	10,937	7,344	8,096	69%	51%	53%
Coal-fired plants	4,820	6,864	6,941	30%	48%	45%
Natural gas fired plants	138	160	242	1%	1%	2%
Total system generation	15,895	14,368	15,279	100%	100%	100%
Purchased power - cogeneration and small power production	1,495	910	970			
Purchased power - other	1,256	1,491	1,942			
Total purchased power	2,751	2,401	2,912			
Total power supply	18,646	16,769	18,191			

***Hydroelectric Generation*:** Idaho Power operates 17 hydroelectric projects located on the Snake River and its tributaries. Together, these hydroelectric facilities provide a total nameplate capacity of 1,709 MW and annual generation equal to approximately 8.6 million megawatt-hours (MWh) under median water conditions. The availability of hydroelectric power depends on the amount of snow pack in the mountains upstream of Idaho Power's hydroelectric facilities, reservoir storage, springtime snow pack run-off, river base flows, spring flows, rainfall, amount and timing of water leases, and other weather and stream flow management considerations. During low water years, when stream flows into Idaho Power's hydroelectric projects are reduced, Idaho Power's hydroelectric generation is reduced.

The manner in which Idaho Power has optimized operation of its hydroelectric facilities in the past has been impacted by intermittent wind generation and may continue to be impacted in the future as the company is faced with integrating an increasing amount of intermittent wind generation. As additional intermittent wind generation resources are developed in the region and contracted to Idaho Power, the operational impacts will likely increase. For related information on intermittent wind generation see "Purchased Power Agreements" below.

Significantly greater snow accumulation during the winter and the resulting effect on stream flow conditions resulted in above average stream flow in 2011, which resulted in a 3.6 million MWh increase in generation from Idaho Power's hydroelectric facilities compared to 2010. The observed stream flow data released in August 2011 by the U.S. Army Corps of Engineers, Northwest Division indicated that Brownlee Reservoir inflow for April through July 2011 was 10.5 million acre-feet (maf), compared to 4.6 maf in April through July 2010 and 5.6 maf in April through July 2009. Annual Brownlee Reservoir inflow for 2011 was 19.3 maf compared to 10.7 maf in 2010 and 11.3 maf in 2009.

Power generation at the Idaho Power hydroelectric power plants on the Snake River also depends on the state water rights held by Idaho Power and the long-term sustainability of the Snake River, tributary spring flows, and the Eastern Snake Plain Aquifer that is connected to the Snake River. Idaho Power continues to participate in water management issues in Idaho that may affect those water rights and resources with the goal to preserve, to the fullest extent possible, the long-term availability of water for use at Idaho Power's hydroelectric projects on the Snake River. For more information on water management issues see Note 10 - "Contingencies" to the consolidated financial statements included in this report.

Idaho Power is subject to the provisions of the FPA as a "public utility" and as a "licensee." As a licensee under Part I of the FPA, Idaho Power and its licensed hydroelectric projects are subject to conditions described in the FPA and related FERC regulations. These conditions and regulations include provisions relating to condemnation of a project upon payment of just compensation, amortization of project investment from excess project earnings, possible takeover of a project after expiration of its license upon payment of net investment, severance damages, and other matters.

Idaho Power obtains licenses for its hydroelectric projects from the FERC, similar to other utilities that operate nonfederal hydroelectric projects on qualified waterways. The licensing process includes an extensive public review process and involves numerous natural resource and environmental issues. The licenses last from 30 to 50 years depending on the size, complexity, and cost of the project. Idaho Power is actively pursuing the relicensing of the Hells Canyon Complex and Swan Falls projects. Idaho Power also has three Oregon licenses under the Oregon Hydroelectric Act, which applies to Idaho Power's Brownlee, Oxbow, and Hells Canyon facilities. For further information on relicensing activities see Part II, Item 7 – "MD&A – Regulatory Matters – Relicensing of Hydroelectric Projects."

***Coal and Natural Gas-Fired Generation*:** Idaho Power co-owns three coal-fired power plants and owns two natural gas-fired combustion turbine power plants. The coal-fired plants are:

- Jim Bridger located in Wyoming, in which Idaho Power has a one-third interest;
- Boardman located in Oregon, in which Idaho Power has a 10 percent interest; and
- Valmy located in Nevada, in which Idaho Power has a 50 percent interest.

The natural gas-fired plants, Danskin and Bennett Mountain, are located in Idaho. The Langley Gulch natural gas-fired combined cycle power plant located in Idaho is currently under construction and is contracted to achieve commercial operation no later than November 1, 2012. Based on the current project status, Idaho Power estimates that the plant will be in service by July 1, 2012.

Fuel Supply - Coal: Idaho Power, through its subsidiary IERCo, owns a one-third interest in BCC, which owns the Jim Bridger mine that supplies coal to the Jim Bridger generating plant, which is operated by PacifiCorp. The mine, located near the Jim Bridger plant, operates under a long-term sales agreement that provides for delivery of coal over a 51-year period ending in 2024 from surface, high-wall, and underground sources. Idaho Power believes that the Jim Bridger mine has sufficient reserves to provide coal deliveries for the term of the sales agreement. Idaho Power also has a coal supply contract providing for annual deliveries of coal through 2014 from the Black Butte Coal Company's Black Butte mine located near the Jim Bridger plant. This contract supplements the Bridger Coal deliveries and provides another coal supply to operate the Jim Bridger plant. The Jim Bridger plant's rail load-in facility and unit coal train provide the opportunity to access other fuel supplies for tonnage requirements above established contract minimums.

The Boardman generating plant receives coal through annual contracts with suppliers from the Powder River Basin in northeast Wyoming. Portland General Electric Company, as the operator of the Boardman plant, has two agreements to supply coal beginning in 2012. All of the Boardman plant's coal requirements in 2012, approximately 50 percent in 2013, and 33 percent in 2014, are under contract. A portion of the 2013 and 2014 coal used will be low sulfur content as Boardman prepares for the 2015 transition to a lower sulfur fuel content. As a ten percent owner of the plant, Idaho Power is obligated to purchase ten percent of the coal purchased under these agreements. In December 2010, the Oregon Environmental Quality Commission approved a plan to cease coal-fired operations at the Boardman power plant not later than December 31, 2020. For additional information, see Part II, Item 7 – "MD&A – Environmental Matters – Environmental Regulation."

NV Energy, Inc., as the operator of the Valmy generating plant, has agreements with coal suppliers through 2015. Idaho Power's share of these agreements along with existing coal inventory at the plant cover Idaho Power's projected coal supply needs for 2012, 2013, and 2014 and approximately 50 percent in 2015. As a 50 percent owner of the plant, Idaho Power is obligated for one-half of the coal purchased under these contracts.

Fuel Supply - Natural Gas: Idaho Power owns and operates the Danskin and Bennett Mountain combustion turbines, and is constructing its Langley Gulch natural gas-fired combined-cycle power plant. Natural gas for all facilities is purchased based on system requirements and dispatch efficiency. The natural gas is supplied through Williams-Northwest Pipeline under Idaho Power's 55,584 million British thermal units (MMBtu) per day long-term gas transportation service agreements. The agreements vary in contract length, with the latest termination date of May 2042, but with extensions at Idaho Power's discretion. In addition to the long-term gas transportation service agreements, Idaho Power has entered into a long-term storage service agreement with Northwest Pipeline for 131,453 MMBtu of total storage capacity at the Jackson Prairie Storage Project. As the project is developed, storage capacity will be phased into service and allocated to Idaho Power on a monthly basis. Idaho Power's current storage allotment is approximately 89 percent of its eventual total, with its full allotment expected to be reached by July 2012. This firm storage contract expires in 2043. Natural gas will be purchased and stored with the intent of fulfilling needs as identified for seasonal peaks or to meet system requirements.

Idaho Power estimates that its Langley Gulch plant will be in service by July 1, 2012, in time to contribute to meeting summer loads. Approximately 1.2 million MMBtu's of natural gas has been hedged using financial instruments for future purchases for start-up testing of the plant expected to take place between March 2012 and May 2012. Along with this, approximately 2.9 million MMBtu's of natural gas has been financially hedged for future purchases for the operational dispatch of Langley Gulch from July 2012 to January 2013. Idaho Power plans to manage the procurement of additional natural gas as necessary to meet system requirements and fueling strategies.

***Purchased Power Agreements*:** Idaho Power purchases power in the wholesale market and pursuant to long-term power purchase contracts, as described below:

Wholesale Market Purchases: Idaho Power purchases power in the wholesale market based on economics, operating reserve margins, risk limits, and unit availability, and from PURPA projects as mandated. Idaho Power seeks to manage its loads efficiently by utilizing its generation resources and long-term purchase power contracts in conjunction with buying and selling opportunities in the wholesale market. Idaho Power has the following notable firm wholesale power purchase contracts and energy exchange agreements:

- PPL Energy Plus, LLC - for 83 MW per hour during heavy load hours, to address increased demand during June, July and August. The contract term is through August 2012;
- Raft River Energy I, LLC - for up to 13 MW (nameplate generation) from its Raft River Geothermal Power Plant Unit #1 located in southern Idaho. The contract term is through April 2033;
- Telocaset Wind Power Partners, LLC - for 101 MW (nameplate generation) from its Elkhorn Valley wind project located in eastern Oregon. The contract term is through 2027;
- USG Oregon LLC - for 22 MW (estimated average annual output) from the to-be-constructed Neal Hot Springs #1 geothermal power plant located near Vale, Oregon. The contract term is 25 years with an option to extend. USG Oregon LLC has stated that it expects commercial operation by late 2012; and
- Clatskanie People's Utility - for the exchange of up to 18 MW of energy from the Arrowrock Project in southern Idaho for energy from Idaho Power's system or power purchased at the Mid-Columbia trading hub. The initial term of the agreement is January 1, 2010 through December 31, 2015. Idaho Power has the right to renew the agreement for two additional five-year terms.

CSPP and PURPA Power Purchase Contracts: Pursuant to the requirements of Section 210 of PURPA, the state regulatory commissions having jurisdiction over Idaho Power have each issued orders and rules regulating Idaho Power's purchase of power from cogeneration and small power production (CSPP) facilities. A key component of the PURPA contracts is the energy price contained within the agreements. PURPA regulations specify that a utility must pay energy prices based on the utility's avoided costs. The "published avoided cost" is a price established by the IPUC and OPUC to estimate Idaho Power's cost of developing additional generation resources. The IPUC and OPUC have established specific rules and regulations to calculate the published avoided cost that Idaho Power is required to include in PURPA contracts.

Idaho Power has contracts for the purchase of energy from a number of private developers. For these contracts:

- Idaho Power is required to purchase all of the output from the facilities located inside its service territory, subject to some exceptions such as adverse impacts on system reliability;
- Idaho Power is required to purchase the output of projects located outside its service territory if it has the ability to receive power at the facility's requested point of delivery on the Idaho Power system;
- the IPUC jurisdictional portion of the costs associated with CSPP contracts is fully recovered through base rates and the PCA, and the OPUC jurisdictional portion is recovered through general rate case filings and the PCAM;
- IPUC jurisdictional regulations allow IPUC published avoided costs for up to a 20-year contract term. Effective December 14, 2010, wind and solar resource projects with a nameplate rating of 100 kW or less are eligible for the IPUC published avoided costs. For all other resource types, a project that generates up to ten average MW of energy monthly is eligible for the IPUC published avoided costs;
- OPUC jurisdictional regulations allow OPUC published avoided costs for up to a 20-year contract term for projects with a nameplate rating of up to ten MW of capacity; and
- if a PURPA project does not qualify for published avoided costs, Idaho Power is required to negotiate the terms, prices, and conditions with the developer. These negotiations reflect the characteristics of the individual projects (i.e., operational flexibility, location, and size) and the benefits to the Idaho Power system and must be consistent with other similar energy alternatives.

Idaho Power believes that published avoided cost rates in effect as of the date of this report provide a favorable climate for PURPA project development. Mandated purchase of intermittent, non-dispatchable energy at published avoided cost rates may result in Idaho Power acquiring energy at above wholesale market prices when a surplus already exists (at times resulting in sale of the surplus energy in the wholesale markets at a loss) and result in additional integration costs, thus increasing costs to its customers. Following a dramatic increase in anticipated PURPA projects, in response to a November 5, 2010 application filed by Idaho Power and two other electric utilities with Idaho service territories, on February 7, 2011, the IPUC issued an order temporarily reducing the eligibility cap for projects obtaining published avoided cost rates, effective retroactively to December 14, 2010, to 100 kW for wind and solar PURPA projects only. On June 8, 2011, the IPUC disapproved 13 contracts for pending wind projects with a combined nameplate capacity of 294 MW. If these 13 contracts had all been approved, the amount of wind generation that Idaho Power had under contract would have exceeded 1,000 MW. The IPUC has opened a docket to further investigate PURPA contract terms and conditions and pricing models. This matter is scheduled for hearings in August 2012. For further information on those proceedings, refer to "MD&A - Regulatory Matters - PURPA Power Purchase Contracts."

As of December 31, 2011, Idaho Power had 40 MW of solar power generation under contract for purchase. In December 2011, Idaho Power entered into a PURPA purchase power agreement for a 20-MW waste biomass generation project. Idaho Power has also entered into a number of other PURPA agreements for smaller renewable energy projects.

As of December 31, 2011, Idaho Power had the following signed CSPP-related agreements with terms ranging from one to 35 years:

Status	**Number of Contracts**	**Nameplate Capacity (MW)**
On-line at the end of 2011	96	606
Contracted and projected to come on-line by year-end 2014	23	383
Total	119	989

The majority of new facilities will be wind resources that will generate on an intermittent basis. During 2011, Idaho Power purchased 1.5 million MWh of power from CSPP facilities at a cost of $90 million, resulting in a blended price of $60.36 per MWh.

Transmission Services

Electric transmission systems deliver energy from electric generation facilities to distribution systems for final delivery to customers. Transmission systems are designed to move electricity over long distances because generation facilities can be located anywhere from a few miles to hundreds of miles from customers. Idaho Power’s generating facilities are interconnected through its integrated transmission system and are operated on a coordinated basis to achieve maximum load-carrying capability and reliability. Idaho Power’s transmission system is directly interconnected with the transmission systems of the Bonneville Power Administration (BPA), Avista Corporation, PacifiCorp, NorthWestern Energy, and NV Energy, Inc. These interconnections, coupled with transmission line capacity made available under agreements with some of the above entities, permit the interchange, purchase, and sale of power among entities in the Western Power System. Idaho Power provides wholesale transmission service and provides firm and non-firm wheeling services for eligible transmission customers. Idaho Power is a member of the WECC, the Western Systems Power Pool, the Northwest Power Pool, the Northern Tier Transmission Group, and the North American Energy Standards Board. These groups have been formed to more efficiently coordinate transmission reliability and planning throughout the western grid.

Resource Planning and Renewable Energy Projects

Integrated Resource Plan: Idaho Power filed its 2011 Integrated Resource Plan (IRP) with the IPUC and OPUC in June 2011. The IRP forecasts Idaho Power’s load and resource situation for the next 20 years, analyzes potential supply-side and demand-side options, and identifies near-term and long-term actions. The 2011 IRP was accepted by the IPUC in December 2011. As of the date of this report the 2011 IRP has not been acknowledged by the OPUC. The four primary goals of the IRP are to:

- identify sufficient resources to reliably serve the growing demand for energy within Idaho Power’s service area throughout the 20-year planning period;
- ensure the selected resource portfolio balances cost, risk, and environmental concerns;
- give equal and balanced treatment to both supply-side resources and demand-side measures; and
- involve the public in the planning process in a meaningful way.

Idaho Power updates the IRP every two years and work on the 2013 IRP will begin in the summer of 2012. Idaho Power expects that the updated plan will be completed and filed in June 2013. During the time between resource plan filings, the public and regulatory oversight of the activities identified in the 2011 IRP allows for discussion and adjustment of the IRP as warranted. Idaho Power makes periodic adjustments and corrections to the resource plan to reflect changes in technology, economic conditions, anticipated resource development, and regulatory requirements.

The 2011 IRP included the 300-MW Langley Gulch project currently under construction and a 50-MW expansion of the Shoshone Falls hydroelectric facility. The 2011 IRP also identified the Boardman-to-Hemingway transmission line in the preferred resource portfolio. Idaho Power believes the Boardman-to-Hemingway transmission line and the Hemingway substation, together with the Gateway West transmission line, will improve reliability, relieve congestion, and provide system flexibility. Additional information about Idaho Power's significant infrastructure development projects are discussed in Part II, Item 7 – "MD&A – Liquidity and Capital Resources – Capital Requirements – Major Infrastructure Projects."

The expected-case load forecast in the 2011 IRP projects peak-hour load will grow 69 MW annually and average-system load will increase annually 29 average MW (aMW) over the 20-year planning period, with an expected-case, median, average annual system load of 2,362 aMW by 2030. Idaho Power intends to meet the anticipated increase in demand through energy efficiency and demand response programs, the development of transmission capacity and additional generation resources, such as the Langley Gulch and Shoshone Falls projects, and from the purchase of power from third parties, including from renewable energy projects and market power purchases. Idaho Power stated in the 2011 IRP that it expects energy efficiency programs to result in 233 aMW of load reduction by 2030, and that demand response programs are targeted to reduce peak summer load by 351 MW by summer 2016.

The 2011 IRP also included discussion related to geothermal, combined heat and power (CHP), and solar resources, each of which is described below.

Geothermal Resources: Idaho Power has continued to work with geothermal project developers capable of delivering energy to the company's service area. The 2009 IRP included two 20-MW increments of geothermal energy in the preferred portfolio—one in 2012 and one in 2016. The 20-MW increment in 2012 was addressed by a long-term power purchase agreement for the output from the Neal Hot Springs geothermal project located in eastern Oregon. This project is currently under construction and the developer expects it to be operational in late 2012. Idaho Power has contracted to receive the RECs from the project during the term of the agreement. The additional 2016 increment of geothermal energy was evaluated in the 2011 IRP and was found unnecessary with the addition of the Boardman-to-Hemingway transmission line project. The preferred portfolio in the 2011 IRP did include 52 MW of geothermal energy in 2021 and Idaho Power plans to follow the development of geothermal resources in and around Idaho Power's service area in the event a project materializes that could fill this need in 2021.

CHP Resources: CHP, also commonly referred to as "cogeneration," facilities utilize by-product heat (often through steam) to generate electricity. CHP resources were not included in the 2011 IRP preferred portfolio because of the uncertainty in being able to successfully develop a CHP project. However, Idaho Power continues to work with large customers and other parties to explore CHP development opportunities.

In 2009, Idaho Power signed an agreement to jointly investigate a CHP project with the Idaho Office of Energy Resources (IOER) and The Amalgamated Sugar Company (TASCO), one of Idaho Power's large industrial customers. The agreement established the framework for a high-level feasibility study to investigate installing a CHP project at TASCO's Nampa, Idaho facility that could generate as much as 100 MW of electricity. The IOER and Idaho Power jointly funded the study, which confirmed initial estimates of the project's potential benefits. In September 2010, Idaho Power, IOER, and TASCO agreed to complete a more detailed feasibility study to refine performance and financial modeling of the proposed project. The second feasibility study indicated that the CHP project is technically feasible; however, given the increase in the amount of PURPA power generation Idaho Power now has under contract, current economic and electric power market conditions, the current treatment of CHP projects under federal incentive programs, and TASCO's and IPC's individual needs, proceeding with developing this CHP project does not appear to be the most economic choice for either party.

Solar Resources: On or before January 1, 2020, Idaho Power is required to own or contract to purchase the capacity and output from a qualifying solar photovoltaic (PV) system with a minimum capacity of 500 kW pursuant to the state of Oregon's solar PV capacity standard. The timing of development of this required project in Oregon and the solar demonstration project referenced in Idaho Power's 2011 IRP will depend in large part on Idaho Power's ability to resolve integration, reliability, and cost issues associated with the recent influx of PURPA resources from which Idaho Power is currently mandated to purchase power. However, with the cost of solar PV technology continuing to decrease, Idaho Power believes this technology will become more prevalent in its service area. Idaho Power continues to evaluate the timing for proceeding with solar resource projects.

Energy Efficiency and Demand Response Programs: Idaho Power has 16 energy efficiency and demand response programs targeting energy savings across the entire year and summer system demand reduction. These programs are offered to all customer segments and emphasize the wise use of energy, especially during periods of high demand. This energy and demand reduction can minimize or delay the need for new infrastructure. Idaho Power's programs include:

- financial incentives for irrigation customers for either improving the energy efficiency of an irrigation system or installing new energy efficient systems;
- energy efficiency for new and existing homes, including efficient appliances and HVAC equipment, energy efficient building techniques, insulation improvement, air duct sealing, and energy efficient lighting;
- incentives to industrial and commercial customers for acquiring energy efficient equipment, and using energy efficiency techniques for operational and management processes; and
- demand response programs to reduce peak summer demand through the voluntary interruption of central air conditioners for residential customers, interruption of irrigation pumps, and reduction of commercial and industrial demand through a third-party demand response aggregator.

In 2011, Idaho Power's energy efficiency programs reduced energy usage by approximately 160,000 MWh. Idaho Power's demand response programs had available capacity of approximately 410 MW; however, because of a relatively mild summer and the restructuring of Idaho Power's irrigation peak rewards program, Idaho Power realized approximately 83 MW in summer peak demand reduction through combined performance.

In 2011, Idaho Power spent approximately $46.3 million on energy efficiency and targeted demand reduction response programs. Approximately $37.7 million of funding for these programs is provided by Idaho and Oregon energy efficiency tariff riders, while the balance of the funding comes from Idaho Power base rates. Beginning in 2011, as approved by the IPUC, Idaho Power capitalized approximately $7 million of custom efficiency program incentives as a regulatory asset.

Approximately $4 million of Idaho Power's 2011 energy efficiency spending was related to research and analysis, education, technology evaluation, and market transformation. Most of this activity was done in conjunction with the Northwest Energy Efficiency Alliance.

Environmental Regulation and Costs

Idaho Power's activities are subject to a broad range of federal, state, regional, and local laws and regulations designed to protect, restore, and enhance the quality of the environment. Environmental regulation continues to impact Idaho Power's operations due to the cost of installation and operation of equipment and facilities required for compliance with environmental regulations, and the modification of system operations to accommodate environmental regulations. In addition to generally applicable regulations, the FERC licenses issued for Idaho Power's hydroelectric generating plants have environmental requirements such as aeration of turbine water to meet dissolved gas and temperature standards in the tail waters downstream from the plants. Idaho Power monitors these issues and reports the results to the appropriate regulatory agencies. Idaho Power co-owns three coal-fired power plants and owns two natural gas combustion turbine power plants that are subject to a broad range of environmental requirements, including air quality regulation. For a more detailed discussion of these and other environmental issues, refer to Part II, Item 7 – "MD&A – Environmental Matters."

Idaho Power's environmental compliance costs will continue to be significant for the foreseeable future, especially with potential additional regulation under discussion at the state and federal levels. Idaho Power estimates its environmental expenditures, based upon present environmental laws and regulations, will be as follows for the periods indicated, excluding allowance for funds used during construction (AFUDC) (in millions of dollars):

Environmental expenditures	**2012**	**2013 - 2014**
Capital expenditures:		
Studies and measures at hydroelectric facilities	$ 12	$ 31
Investments in equipment and facilities at thermal plants	15	99
Total capital expenditures	$ 27	$ 130
Operating expenses:		
Operating costs for environmental facilities - hydroelectric	$ 21	$ 48
Operating costs for environmental facilities - thermal	12	27
Total operations and maintenance	$ 33	$ 75

Idaho Power anticipates that a number of new and impending EPA rulemakings and proceedings addressing, among other things, ozone and fine particulate matter pollution, emissions, and disposal of coal combustion residuals could result in substantially increased operating and compliance costs in addition to the amounts set forth above.

IFS

IFS invests primarily in affordable housing developments, which provide a return principally by reducing federal and state income taxes through tax credits and accelerated tax depreciation benefits. IFS generated tax credits of $6 million, $7 million, and $8 million in 2011, 2010, and 2009, respectively. IFS's portfolio also includes historic rehabilitation projects such as the Empire Building in Boise, Idaho. IFS made no new investments in 2011, but did have $7 million and $14 million in new investments during 2010 and 2009, respectively, and will continue to evaluate new opportunities for investment commensurate with the ongoing needs of IDACORP.

IFS has focused on a diversified approach to its investment strategy in order to limit both geographic and operational risk. Over 90 percent of IFS's investments have been made through syndicated funds. At December 31, 2011, the gross amount of IFS's portfolio equaled $198 million in tax credit investments. These investments cover 49 states, Puerto Rico, and the U.S. Virgin Islands. The underlying investments include nearly 700 individual properties, of which all but five are administered through syndicated funds.

IDA-WEST

Ida-West operates and has a 50 percent interest in nine hydroelectric plants with a total generating capacity of 45 MW. Four of the projects are located in Idaho and five are in northern California. All nine projects are "qualifying facilities" under PURPA. Idaho Power purchased all of the power generated by Ida-West's four Idaho hydroelectric projects at a cost of $9 million, $8 million, and $9 million in 2011, 2010, and 2009, respectively.

EXECUTIVE OFFICERS OF THE REGISTRANTS

The names, ages, and positions of the executive officers of IDACORP and Idaho Power are listed below, along with their business experience during at least the past five years. Mr. J. LaMont Keen and Mr. Steven R. Keen are brothers. There are no other family relationships among these officers, nor is there any arrangement or understanding between any officer and any other person pursuant to which the officer was elected.

Senior Executive Officers (in alphabetical order)

DARREL T. ANDERSON, 53
- President and Chief Financial Officer of Idaho Power Company, January 1, 2012 - present.
- Executive Vice President, Administrative Services and Chief Financial Officer of IDACORP, Inc., October 1, 2009 - present.
- Executive Vice President, Administrative Services and Chief Financial Officer of Idaho Power Company, October 1, 2009 - December 31, 2011.
- Senior Vice President - Administrative Services and Chief Financial Officer of IDACORP, Inc. and Idaho Power Company, July 1, 2004 - October 1, 2009.

REX BLACKBURN, 56
- Senior Vice President and General Counsel, IDACORP, Inc. and Idaho Power Company, April 1, 2009 - present.
- Senior Attorney, Idaho Power Company, January 1, 2008 - March 31, 2009.
- Partner at Blackburn and Jones, LLP, a law firm, January 2003 - December 31, 2007.

LISA A. GROW, 46
- Senior Vice President, Power Supply of Idaho Power Company, October 1, 2009 - present.
- Vice President – Delivery Engineering and Operations of Idaho Power Company, July 20, 2005 - September 30, 2009.

J. LAMONT KEEN, 59
- President and Chief Executive Officer of IDACORP, Inc., July 1, 2006 - present.
- Chief Executive Officer of Idaho Power Company, November 17, 2005 - present.
- President of Idaho Power Company, March 1, 2002 - December 31, 2011.
- Executive Vice President of IDACORP, Inc., March 1, 2002 - July 1, 2006.
- Member of the Boards of Directors of both IDACORP, Inc. and Idaho Power Company.

STEVEN R. KEEN, 51
- Senior Vice President, Finance and Treasurer of Idaho Power Company, January 1, 2012 - present.
- Vice President, Finance and Treasurer of IDACORP, Inc., June 1, 2010 - present.
- Vice President, Finance and Treasurer of Idaho Power Company, June 1, 2010 - December 31, 2011.
- Vice President and Treasurer of IDACORP, Inc. and Idaho Power Company, June 1, 2006 - May 31, 2010.
- President of IDACORP Financial Services, January 15, 1999 - May 31, 2007.

DANIEL B. MINOR, 54
- Executive Vice President and Chief Operating Officer of Idaho Power Company, January 1, 2012 - present.
- Executive Vice President of IDACORP, Inc., May 20, 2010 - present.
- Executive Vice President, Operations of Idaho Power Company, October 1, 2009 - December 31, 2011.
- Senior Vice President – Delivery of Idaho Power Company, July 1, 2004 - October 1, 2009.

Other Executive Officers (in alphabetical order)

DENNIS C. GRIBBLE, 59
- Vice President and Chief Information Officer of Idaho Power Company, June 1, 2006 - present.
- Vice President and Chief Information Officer of IDACORP, Inc., June 1, 2006 - December 31, 2011.
- Vice President and Treasurer of IDACORP, Inc. and Idaho Power Company, July 15, 2004 - June 1, 2006.

PATRICK A. HARRINGTON, 51
- Corporate Secretary of IDACORP, Inc. and Idaho Power Company, March 15, 2007 - present.
- Senior Attorney, IDACORP, Inc. and Idaho Power Company, June 7, 2003 - March 15, 2007.

WARREN KLINE, 56

- Vice President, Customer Operations of Idaho Power Company, May 20, 2010 - present.
- Vice President – Customer Service and Regional Operations of Idaho Power Company, July 20, 2005 - May 20, 2010.

JEFFREY MALMEN, 44

- Vice President, Public Affairs of IDACORP, Inc. and Idaho Power Company, October 1, 2008 - present.
- Senior Manager – Governmental Affairs of IDACORP, Inc. and Idaho Power Company, December 10, 2007 - October 1, 2008.
- Chief of Staff of the Office of Idaho Governor C.L. "Butch" Otter, January 2007 - November 2007.
- Chief of Staff of the Office of Idaho Congressman C.L. "Butch" Otter, January 2001 - December 2006.

LUCI K. MCDONALD, 54

- Vice President, Human Resources and Corporate Services of Idaho Power Company, May 20, 2010 - present
- Vice President, Human Resources and Corporate Services of IDACORP, Inc., May 20, 2010 - December 31, 2011.
- Vice President – Human Resources of IDACORP, Inc. and Idaho Power Company, December 6, 2004 - May 20, 2010.

KEN W. PETERSEN, 48

- Corporate Controller and Chief Accounting Officer of IDACORP, Inc. and Idaho Power Company, May 20, 2010 - present.
- Corporate Controller of IDACORP and Idaho Power Company, December 29, 2007 - May 20, 2010.
- General Manager Delivery Services and Delivery Business Unit Controller of Idaho Power Company, January 3, 2004 - December 28, 2007.

N. VERN PORTER, 52

- Vice President, Delivery Engineering and Operations, Idaho Power Company, October 1, 2009 - present.
- General Manager of Power Production of Idaho Power Company, April 22, 2006 - October 1, 2009.
- Senior Manager of Power Supply Operations of Idaho Power Company, August 30, 2003 - April 22, 2006.

GREGORY W. SAID, 57

- Vice President, Regulatory Affairs, Idaho Power Company, January 20, 2011 - present.
- General Manager of Regulatory Affairs, Idaho Power Company, April 3, 2010 - January 20, 2011.
- Director, State Regulation, Idaho Power Company, August 23, 2008 - April 3, 2010.
- Manager, Revenue Requirement, Idaho Power Company, November 14, 1998 - August 23, 2008.

NAOMI SHANKEL, 40

- Vice President, Supply Chain of Idaho Power Company, May 20, 2010 - present.
- Vice President, Supply Chain of IDACORP, Inc., May 20, 2010 - December 31, 2011.
- Vice President, Audit and Compliance of IDACORP, Inc. and Idaho Power Company, September 21, 2006 - May 20, 2010.
- Director, Audit Services of IDACORP, Inc. and Idaho Power Company, July 19, 2003 - September 21, 2006.

LORI D. SMITH, 51

- Vice President, Chief Risk Officer of IDACORP, Inc. and Idaho Power Company, May 20, 2010 - present.
- Vice President - Corporate Planning and Chief Risk Officer of IDACORP, Inc. and Idaho Power Company, January 1, 2008 - May 20, 2010.
- Vice President - Finance and Chief Risk Officer of IDACORP, Inc. and Idaho Power Company, July 1, 2004 - January 1, 2008.

ITEM 1A. RISK FACTORS

In addition to the factors discussed elsewhere in this report, the risk factors set forth below may have a significant impact on the business, financial condition, or results of operations of IDACORP and Idaho Power and could cause actual results or outcomes to differ materially from those discussed in any forward-looking statements.

If the Idaho Public Utilities Commission, the Oregon Public Utility Commission, or the Federal Energy Regulatory Commission grant less rate recovery in regulatory proceedings than Idaho Power needs to cover existing and future costs and earn a rate of return, earnings and cash flows may be reduced. The prices that the Idaho Public Utilities Commission and Oregon Public Utility Commission authorize Idaho Power to charge for its retail services, and the tariff rate that the Federal Energy Regulatory Commission permits Idaho Power to charge for transmission, are generally the most significant factors influencing IDACORP's and Idaho Power's financial position, results of operations, and liquidity. The Idaho Public Utilities Commission and Oregon Public Utility Commission have the authority to disallow recovery of any costs that they consider unreasonable or imprudently incurred. Also, the rates allowed by the Federal Energy Regulatory Commission for transmission service may be insufficient for recovery of costs incurred. While the Idaho Public Utilities Commission and Oregon Public Utility Commission have established an authorized rate of return for Idaho Power, the regulatory process does not provide assurance that Idaho Power will be able to achieve the authorized rate of return. Further, while the Idaho Public Utilities Commission and Oregon Public Utility Commission are required to establish rates that are fair, just, and reasonable, they have considerable discretion in applying this standard. The ratemaking process typically involves multiple parties, including governmental bodies, consumer advocacy groups, and customers. While each party has differing concerns, they often have the common objective of limiting rate increases or even reducing rates. Idaho Power cannot predict the outcome of ratemaking proceedings, including the extent to which costs, including the costs of significant capital projects, will be recovered or what rates of return will be authorized. The failure of Idaho Power to recover those costs, or recover them in a timely manner, may decrease IDACORP's and Idaho Power's earnings and adversely impact cash flows.

For additional information relating to Idaho Power's regulatory framework, see Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report and "Regulatory Matters" in Part II, Item 7 - "Management's Discussion and Analysis of Financial Condition and Results of Operations" in this report.

Idaho Power's cost recovery deferral mechanisms may not function as intended, which may adversely affect cash flows and liquidity. Idaho Power has power cost adjustment mechanisms that provide for periodic adjustments to the rates charged to its Idaho and Oregon retail customers. The power cost adjustment tracks Idaho Power's actual net power supply costs (primarily fuel and purchased power less off-system sales) and compares these amounts to net power supply costs currently being recovered in retail rates. A majority, but not all, of the variance between these two amounts is deferred for future recovery from, or refund to, customers. Accordingly, the power cost adjustment mechanisms only partially offset the potentially adverse financial impacts of forced generating plant outages, severe weather, reduced hydroelectric generation, and volatile wholesale energy prices. Because of the power cost adjustment mechanisms, the primary financial impact of power supply cost variations is on the timing of cash flows. When costs rise above the level recovered in retail base rates it adversely affects Idaho Power's operating cash flow and liquidity until those costs are recovered from customers.

Idaho Power also has a fixed cost adjustment, which began as a pilot program for Idaho Power's Idaho residential and small general service customers, running from 2007 through 2011. The fixed cost adjustment is designed to remove Idaho Power's disincentive to invest in energy efficiency programs by separating (or decoupling) the recovery of fixed costs from the variable kilowatt-hour charge, and linking it instead to a set amount per customer. In October 2011, Idaho Power filed an application with the Idaho Public Utilities Commission requesting that the fixed cost adjustment pilot program become permanent. As of the date of this report, the Idaho Public Utilities Commission has not issued a determination. If the fixed cost adjustment is not approved as permanent, or if the Idaho Public Utilities Commission modifies the fixed cost adjustment in some manner, Idaho Power may incur fixed costs that may not be recoverable in rates in times of declining usage per residential and small general service customer, or may recover more than the fixed costs incurred in times of increasing usage per residential and small general service customer. This over- or under-collection of fixed costs would likely continue until Idaho Power's next Idaho general rate case when the recovery of fixed costs through base rates can be realigned, which could adversely affect Idaho Power's cash flows and liquidity.

For additional information relating to Idaho Power's regulatory framework and cost recovery mechanisms, see Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report and "Regulatory Matters" in Part II, Item 7 - "Management's Discussion and Analysis of Financial Condition and Results of Operations" in this report.

Reduced hydroelectric generation can reduce revenues and increase costs, and reduce earnings and cash flows. Idaho Power derives a significant portion of its power supply from its hydroelectric facilities. Because of Idaho Power's heavy reliance on hydroelectric generation, the availability of water can significantly affect its operations. When hydroelectric generation is reduced, Idaho Power must increase its use of generally more expensive thermal generating resources and purchased power; therefore, opportunities for off-system sales are reduced, which reduces revenues. The further integration of wind and other intermittent power sources into Idaho Power's system may also displace lower cost hydroelectric resources. Integration of intermittent power sources may also increase costs at thermal plants due to wear and tear associated with frequent start-up and shut-down of those facilities to balance loads. While Idaho Power expects to recover, as a result of its power cost adjustment mechanisms, the majority of its net power supply costs above current rates (including the power cost adjustment forecast), recovery of the excess amounts may not occur until the subsequent power cost adjustment year, impacting cash flows and liquidity.

Declines in stream flows and over-appropriation of water in Idaho may reduce hydroelectric generation and revenues and increase costs, and reduce earnings and cash flows. The combination of declining Snake River base flows, over-appropriation of water, and periods of drought have led to water rights disputes and proceedings among surface water and ground water irrigators and the State of Idaho. Recharging the Eastern Snake Plain aquifer by diverting surface water to porous locations and permitting it to sink into the aquifer is one proposed solution to the over-appropriation dispute. Diversions from the Snake River for aquifer recharge or the loss of water rights may further reduce Snake River flows available for hydroelectric generation. Idaho Power's January 2010 settlement agreement with the State of Idaho resolves litigation regarding certain Idaho Power water rights on the Snake River and provides for ongoing Snake River water issues to be addressed in a comprehensive aquifer management plan process. However, there is no assurance that this process will lead to increased Snake River stream flows for Idaho Power's hydroelectric projects. The comprehensive aquifer management plan process and the resolution of pending proceedings relating to the Snake River may affect Snake River flows available for hydroelectric generation and thereby reduce Idaho Power's revenues and increase costs, and may reduce earnings and cash flows.

Idaho Power's reliance on coal and natural gas to fuel its power generation facilities exposes it to risk of increased costs and reduced earnings. In addition to hydroelectric generation, Idaho Power relies on coal and natural gas to fuel its generation facilities. As part of its normal business operations, Idaho Power purchases power and natural gas in the open market or under short-term, long-term, or variable-priced contracts. Market prices for coal and natural gas are influenced by factors impacting supply and demand, such as weather conditions, fuel transmission or transportation availability, economic conditions, and changes in technology. Increases in demand for coal or natural gas may result in market price increases, short-term price volatility, and supply availability issues. Any disruption in Idaho Power's fuel supply may require the company to find alternative fuel sources at higher costs, to produce power from higher cost generation facilities, or to purchase power from other sources at higher costs. Idaho Power may not be able to fully recover these increased costs through ratemaking, which may reduce earnings. Further, Idaho Power's power cost adjustment mechanisms contain a cost-sharing feature that does not in all circumstances provide for full recovery of incurred costs in customer rates.

Idaho Power's power generating facilities are subject to numerous operational risks unique to it and its industry. Operating risks associated with Idaho Power's generation facilities include equipment failures, volatility in fuel and transportation pricing, interruptions in fuel supplies, increased regulatory compliance costs, labor disputes, workforce safety matters, the loss of cost-effective disposal options for solid waste, operator error, and the occurrence of catastrophic events at the facilities. Diminished availability or performance of Idaho Power's transmission and distribution facilities could result in reduced customer satisfaction and regulatory inquiries and fines. Operation of Idaho Power's owned and co-owned generating stations below expected capacity levels, or unplanned outages at these stations, could cause reduced energy output and lower efficiency levels and result in lost revenues and increased expenses. These operational risks may result in plant outages, as well as increased operation and maintenance expenses, power generation costs, and power purchase costs, which could have an adverse impact on earnings and cash flows.

Load changes in Idaho Power's service territory expose Idaho Power to greater market and operational risk and could increase costs and reduce earnings and cash flows. While Idaho Power's customer growth rate has slowed in recent years, increases in both the number of customers and the demand for energy have resulted and may continue to result in increased reliance on purchased power to meet peak system demand. While Idaho Power is exploring targeted opportunities for managed load growth, load growth can create planning and operating difficulties for Idaho Power that can negatively impact its ability to reliably serve customers. Through current regulatory mechanisms, Idaho Power can expect to recover the majority of the net power supply costs above the amounts included in its rates, though recovery of the excess amounts does not occur until the subsequent power cost adjustment year, and the remaining amount is absorbed by Idaho Power, which could increase costs and reduce earnings and cash flows. Load growth can also result in the need for additional investments in Idaho Power's infrastructure to serve the new load. For instance, to meet customer demand Idaho Power is currently constructing its Langley

Gulch natural gas-fired generating plant, and has in development a number of transmission projects. If Idaho Power is unable to secure timely rate relief from the Idaho Public Utilities Commission, the Oregon Public Utility Commission, or the Federal Energy Regulatory Commission to recover the costs of these additional investments, the resulting disconnect between the time investments are made and costs are recovered would have a negative effect on earnings and cash flows. Further, while Idaho Power has experienced a general trend of load growth in its service territory in recent years, increased emphasis on energy efficiency and weak economic conditions could result in a decline in loads, which may decrease Idaho Power's revenues from energy sales. Also, Idaho Power's regulatory mechanisms, including its load change adjustment rate included in its power cost adjustment, may not result in Idaho Power recovering all of its costs associated with load decreases, which would have a negative impact on earnings and cash flows.

Federally mandated purchases of power from PURPA power purchase projects, and integration of power generated from those projects into Idaho Power's system, may increase costs and decrease system reliability, and adversely affect cash flows, financial condition, and earnings. An abundance of intermittent, non-dispatchable wind power generation at times when Idaho Power has available lower-cost resources to meet load demands has an impact on the operation of Idaho Power's hydroelectric generation plants, system reliability, power supply costs, and the wholesale power markets in the Pacific Northwest. Wind power generated from PURPA projects, which Idaho Power is generally obligated to purchase regardless of the then-current load demand or wholesale energy market prices, increases the likelihood and frequency that Idaho Power will be required to reduce output from its lower-cost hydroelectric and fossil fuel-fired generation resources, even when weather conditions have resulted in favorable hydroelectric generation conditions or fuel prices are low. Wind generation in the Pacific Northwest during periods when abundant hydroelectric generation is also available reduces wholesale market prices. This may result in Idaho Power's sale of excess wind power at a significant discount to the price Idaho Power paid for the wind power under PURPA wind power purchase contracts. It may also result in the sale of excess lower-cost hydroelectric or fuel-based power at depressed wholesale market prices. When forecasted wind or other intermittent resources do not materialize, Idaho Power must obtain a substitute source of power to meet load demand, and often must purchase power in the wholesale power markets to balance loads. Further, balancing load and generation from Idaho Power's power generation portfolio is challenging, and Idaho Power expects that its costs will increase as a result of its efforts to integrate intermittent, non-dispatchable power from a large number of PURPA power projects. Idaho Power anticipates that those costs will escalate as the volume of wind and other intermittent power on Idaho Power's system increases, which may adversely affect IDACORP's and Idaho Power's cash flows, financial condition, and earnings.

Weather and climate change could affect customer demand and hydroelectric generation and disrupt transmission and distribution systems, reducing earnings and cash flows. Warmer than normal winters, cooler than normal summers, and increased rainfall during the irrigation seasons reduce retail revenues from power sales and may impact the amount and timing of hydroelectric generation. Changes in the amount and timing of snowpack and stream flows may also adversely affect hydroelectric generation. Extreme weather events and their associated impacts, such as high winds and fires, can disrupt transmission and distribution systems and cause service interruptions and extended outages, increase supply chain costs, potentially interrupt use of generation resources, and limit Idaho Power's ability to meet customer energy demand. Rapid increases in load requirements resulting from unexpected adverse weather changes, particularly if coupled with transmission constraints or system damage, could adversely impact Idaho Power's costs and ability to meet customer energy demand. Conversely, rapid decreases in load requirements due to unexpected weather events could result in Idaho Power's sale of excess energy at depressed wholesale market prices. Disruption in generation, transmission, and distribution systems due to weather-related factors also increases operations and maintenance expenses and reduces earnings and cash flows.

Long-term climate change could increase the likelihood and frequency of these adverse weather events. Further, legislative and/or regulatory developments associated with climate change could affect construction plans and operations, including placing restrictions on the construction of new generation resources and the expansion of existing resources, result in closure of generation resources or installation of costly pollution control equipment, or require changes to the operation of generation resources and Idaho Power's power generation portfolio in general. Also, consumer preference for renewable or low greenhouse gas-emitting sources of energy could impact demand from existing sources and require significant investment in new generation and transmission resources. Any of these effects of weather and climate change could decrease revenues, increase operating costs, and reduce IDACORP’s and Idaho Power’s earnings and cash flows.

In Idaho Power's service territory, demand for power peaks during the hot summer months, often concurrent with a seasonal increase in wholesale power market prices. As a result, Idaho Power's operating results fluctuate substantially on a seasonal basis. In addition, Idaho Power will generally sell less power, and correspondingly have lower net income, when weather conditions in its service areas are milder. Unusually mild weather in the future could diminish IDACORP's and Idaho Power's results of operations and adversely affect its financial condition.

Idaho Power's risk management policy and programs relating to economically hedging power and gas exposures, financial and interest rate risk, and counterparty creditworthiness may not always perform as intended, and as a result Idaho Power may suffer economic losses. Idaho Power enters into transactions to hedge its positions in coal, natural gas, power, and other commodities. These hedging transactions are impacted by a range of factors, including variations in power demand, fluctuations in market prices, and market prices for alternative commodities. In connection with these hedging transactions, Idaho Power is exposed to the risk that counterparties that owe it money will default on their obligations. A similar risk of non-performance by third parties arises where those parties are obligated to purchase energy from, or sell energy to, Idaho Power, or are parties to commodity price risk management arrangements. Idaho Power actively manages the market risk inherent in its energy related activities and counterparty credit positions by establishing and enforcing risk limits and risk management policies. Idaho Power has procedures that monitor compliance with its risk management policies and programs, including verification of transactions, regular portfolio reporting of various risk management metrics, and daily counterparty credit risk analysis. However, actual hydroelectric and thermal generation, power purchase volumes from intermittent sources, transmission availability, and market prices may be significantly different than those originally planned for when Idaho Power enters into its positions in hedging transactions. This creates uncertainty in the appropriate amount of hedging activity to pursue. Forecasts of future loads and available resources to meet those loads are inherently uncertain and may cause Idaho Power to over- or under-hedge actual resource needs, exposing the company to market risk on the over- or under-hedged position. Changes in market prices are also unpredictable and can at times result in Idaho Power's hedged positions performing less favorably than unhedged positions. In addition, Idaho Power's counterparty credit policies may not prevent counterparties from failing to perform, forcing the company to replace forward contracts with transactions in the open market, where the price for the particular commodity may at that time be higher. As a result, risk management decisions may adversely affect IDACORP's and Idaho Power's financial condition, results of operations, or cash flows.

Also, as part of IDACORP's and Idaho Power's risk management programs, they may use a variety of non-derivative and derivative financial instruments, such as swaps, futures, and forwards, to manage market risks. They may also use interest rate derivative instruments to hedge against interest rate fluctuations related to debt. In the absence of actively quoted market prices and pricing information from external sources, the valuation of some of the derivative instruments involves management's judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of some of the contracts. IDACORP or Idaho Power could also recognize financial losses as a result of volatility in the market values of these contracts or if a counterparty fails to perform, which could adversely affect IDACORP's or Idaho Power's results of operations, financial condition, and cash flows.

Idaho Power's ability to enter into swaps and derivatives and hedge commodity and interest rate risk may be adversely affected by recent federal legislation. The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) was signed into law in July 2010. The Dodd-Frank Act establishes regulatory jurisdiction by the Commodity Futures Trading Commission and the Securities and Exchange Commission for certain swaps and derivative instruments and the users of those instruments. A number of federal agencies, including the Commodity Futures Trading Commission and the Securities and Exchange Commission, must adopt rules to implement the Dodd-Frank Act. As Idaho Power enters into swap and derivative transactions from time to time in connection with its general business operations, these rules, when implemented, could have a significant impact on Idaho Power and will likely increase the costs Idaho Power incurs in connection with its swap and derivative transactions. Under the rules, Idaho Power may be required to post collateral to meet minimum capital and margin requirements. The Dodd-Frank Act also requires a broad category of swaps to be cleared and traded on registered exchanges or special derivatives exchanges. These clearing requirements would result in a significant change from Idaho Power's current practice of bilateral transactions and negotiated credit terms. The Dodd-Frank Act outlines an elective exemption to the clearing requirements for swaps entered into by end users that are not "major swap participants" or "swap dealers" and that enter into hedges to mitigate their own commercial risk. Although Idaho Power expects that its swaps will qualify under the end user exemption, there can be no assurance they will qualify. Further, even if Idaho Power's swaps were to qualify under the end user exemption, it will not be exempt from all swap-related requirements of the Dodd-Frank Act, and counterparties that are swap dealers or major swap participants may seek to pass along the increased cost and margin requirements through higher prices and reductions in unsecured credit limits. The occurrence of these events could have an adverse effect on IDACORP's and Idaho Power's results of operations, financial condition, and cash flows.

Capital expenditures for power generation and delivery infrastructure and replacement of that infrastructure can significantly affect liquidity. Idaho Power's business is capital intensive and requires significant investments in energy generation and other infrastructure projects. Long-term increases in both the number of customers and the demand for energy require expansion and reinforcement of transmission and distribution systems, generating facilities, and other infrastructure. For instance, Idaho Power is currently constructing the Langley Gulch power plant and is in the permitting process for two substantial 500-kV transmission line projects. The cost of maintaining existing, aging equipment and infrastructure and developing new infrastructure is substantial, and involves risks relating to, among other things, cost overruns, system outages, price increases in commodities (such as steel and copper), and denial by regulatory bodies of recovery through rates of costs incurred. Idaho Power may not be successful in limiting capital expenditures to planned amounts, particularly in the event of escalating costs for materials and labor. If Idaho Power does not receive timely regulatory recovery of costs associated with those expansion and reinforcement activities, Idaho Power will have to rely more heavily on external debt or equity financing for its future capital expenditures. These large capital expenditures may weaken the consolidated financial profile of IDACORP and Idaho Power. Additionally, a significant portion of Idaho Power's facilities were constructed many years ago, which could affect reliability, increase repair and maintenance expenses, and increase reliance on market purchases of power.

The performance of pension and postretirement benefit plan investments and other factors impacting plan costs could adversely affect cash flows and liquidity. Idaho Power provides a noncontributory defined benefit pension plan covering most employees, as well as a defined benefit postretirement benefit plan (consisting of health care and death benefits) that covers eligible retirees. Costs of providing these benefits are based in part on the value of the plans' assets and, therefore, adverse investment performance for these assets could increase Idaho Power's funding requirements related to the plans. The key actuarial assumptions that affect funding obligations are the expected long-term return on plan assets and the discount rate used in determining future benefit obligations. Idaho Power evaluates the actuarial assumptions on an annual basis, taking into account changes in market conditions, trends, and future expectations. Estimates of future equity and debt market performance, changes in interest rates, and other factors Idaho Power and its actuary firms use to develop the actuarial assumptions are uncertain, and actual results could vary significantly from the estimates. Changes in demographics, including increased numbers of retirements or changes in life expectancy assumptions, may also increase Idaho Power's funding requirements for the pension and other postretirement benefit plans. Future pension funding requirements, and the timing of funding payments, may also be subject to changes in legislation. Depending on the timing of contributions to the plans and the availability of recovery of costs through rates, cash contributions to the plans could reduce the cash available for operating activities. For additional information regarding Idaho Power's funding obligations under its benefit plans, see Note 11 - "Benefit Plans" to the consolidated financial statements included in this report.

Idaho Power's business is subject to substantial governmental regulation, including environmental laws and mandatory reliability standards, which could increase costs. Idaho Power is subject to an extensive body of federal and state laws, policies, and regulations, as well as regulatory actions and regulatory audits, including those of the Federal Energy Regulatory Commission, the Environmental Protection Agency, the North American Electric Reliability Corporation, the Western Electricity Coordinating Council, and the public utility commissions in Idaho, Oregon, and Wyoming. Some of these regulations are changing or subject to interpretation, and failure to comply may result in penalties or other adverse consequences.

As an owner and operator of a bulk power transmission system, Idaho Power is subject to mandatory reliability standards issued by the North American Electric Reliability Corporation and enforced by the Federal Energy Regulatory Commission. The standards are based on the functions that need to be performed to ensure the bulk power system operates reliably and are guided by reliability and market interface principles. Compliance with reliability standards subjects Idaho Power to higher operating costs and increased capital expenditures. Further, Idaho Power has received notice of violations from, and self-reported reliability standard compliance issues to, the Federal Energy Regulatory Commission, the North American Electric Reliability Corporation, and the Western Electricity Coordinating Council, and has several matters pending. Potential monetary and non-monetary penalties for a violation of Federal Energy Regulatory Commission regulations may be substantial, and in some circumstances monetary penalties may be as high as $1 million per day per violation. The imposition of penalties on Idaho Power could have an adverse impact on its and IDACORP's results of operations, financial condition, and cash flows.

Idaho Power is also subject to extensive federal, state, and local environmental statutes, rules, and regulations relating to air quality, water quality, natural resources, and health and safety. Compliance with these environmental statutes, rules, and regulations involves significant capital and operating expenditures and carries with it the risk of penalties and fines. These laws and regulations generally require Idaho Power to obtain and comply with a wide variety of environmental licenses, permits, inspections, and other approvals, and may be enforced by both public officials and private individuals. Idaho Power cannot predict the outcome or effect of any action or litigation that may arise from applicable environmental regulations. In addition, Idaho Power cannot predict with certainty the amount or timing of future expenditures related to environmental matters because of the difficulty of estimating clean up costs or mitigation measures. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all potentially responsible parties. Environmental regulations may also require Idaho Power to install pollution control equipment at, or perform environmental remediation on, its or its co-owned facilities, often at a substantial cost.

Emissions of nitrogen and sulfur oxides, mercury, and particulates from fossil fueled generating plants are potentially subject to increased regulations, controls, and mitigation expenses. Certain federal legislators, environmental advocacy groups, and regulatory agencies in the United States have also been focusing considerable attention on CO_2 and other emissions from power generation facilities and their potential role in climate change and/or regional air quality compliance. Existing environmental regulations regarding air emissions (such as NOx, SO_2, or mercury emissions), water quality, and other toxic pollutants may be revised or new climate change laws or regulations may be adopted or become applicable to Idaho Power. Moreover, there are many legislative and rulemaking initiatives pending at the federal and state level that are aimed at the reduction of fossil fuel plant emissions. Idaho Power cannot predict the outcome of pending or future legislative and rulemaking proposals. Future changes in environmental laws or regulations governing emissions reduction could make certain electric generating units (especially coal-fired units) uneconomical and subject to shut-down, could require the adoption of new methodologies or technologies that significantly increase costs or delay in-service dates, and may raise uncertainty about the future viability of fossil fuels as an energy source for new and existing electric generation facilities. Modification of existing environmental regulations or adoption of new environmental regulations may result in increased capital expenditures and could increase the cost of operating Idaho Power's generating plants or make them uneconomical to operate and result in reduced earnings and cash flows.

Furthermore, Idaho Power may not be able to obtain or maintain all environmental regulatory approvals necessary for operation of its facilities and execution of its long-term strategy, including construction of new transmission and distribution infrastructure. If there is a delay in obtaining any required environmental regulatory approval or if Idaho Power fails to obtain, maintain, or comply with any such approval, construction and/or operation of Idaho Power's owned or co-owned generation and/or transmission facilities could be delayed, halted, or subjected to additional costs.

Complying with state or federal renewable portfolio standards could increase capital expenditures and operating costs and reduce earnings and cash flows. A number of states have adopted renewable portfolio standards, which require that electricity providers obtain a minimum percentage of their power from renewable energy sources by a specified date. Idaho Power’s operations in Oregon will be required to comply with a ten percent renewable portfolio standard beginning in 2025, and it is possible that other states, including Idaho, could adopt renewable portfolio standards that are applicable to Idaho Power in the future. The cost of purchasing or generating power from renewable energy sources is often greater than fossil fuel and hydroelectric generation sources, and construction of renewable energy facilities involves significant capital expenditures. As a result, new state or federal renewable portfolio standards could increase capital expenditures and operating costs and reduce earnings and cash flows.

The listing as threatened or endangered under the Endangered Species Act of fish, wildlife, or plant species that are found in the areas of Idaho Power’s generation facilities or transmission lines may require mitigation, affect the location of a project or the ability to construct a project, and increase capital expenditures and operating costs. Relicensing of the Hells Canyon and Swan Falls hydroelectric projects and construction of the Gateway West and Boardman-to-Hemingway transmission lines requires consultation under the Endangered Species Act to determine the effects of these projects on any listed species within the project areas. The listing of species as threatened or endangered, including the relatively recent listing of slickspot peppergrass as a threatened species, will result in an Endangered Species Act consultation for the Gateway West and Boardman-to-Hemingway transmission lines and future transmission projects. Similarly, the presence of sage grouse in the vicinity of the Gateway West and Boardman-to-Hemingway transmission projects has required more extensive, costly, and time consuming evaluation and engineering. These and other requirements of the Endangered Species Act and similar laws may increase costs and reduce earnings and cash flows.

Conditions imposed in connection with hydroelectric license renewals may require large capital expenditures, increase operating costs, reduce hydroelectric generation, and reduce earnings and cash flows. Idaho Power is currently involved in renewing federal licenses for some of its hydroelectric projects, including its largest hydroelectric generation source, the Hells Canyon Complex. Relicensing includes an extensive public review process that involves numerous natural resource issues and environmental conditions. The listing of various species of marine life, wildlife, and plants as threatened or endangered has resulted in significant changes to federally-authorized activities, including those of hydroelectric projects. In particular, fish and other marine life recovery plans may require major operational changes to the region’s hydroelectric projects. In addition, new interpretations of existing laws and regulations could be adopted or become applicable to hydroelectric facilities, which could further increase required expenditures for marine life recovery and endangered species protection and reduce the amount of hydroelectric generation available to meet Idaho Power’s energy requirements.

In 2007, the Federal Energy Regulatory Commission Staff issued a final environmental impact statement for the Hells Canyon Complex, which the Federal Energy Regulatory Commission will use in part to determine whether, and under what conditions, to issue a new license for the Hells Canyon Complex. Certain portions of the final environmental impact statement involve issues that may be influenced by water quality certifications for the project under Section 401 of the Clean Water Act and formal consultations under the Endangered Species Act, which remain unresolved. One significant issue involves water temperature gradients, and certain parties in the Hells Canyon Complex relicensing proceedings have advocated for the installation of water temperature management apparatus which, if required to be installed, would require substantial capital expenditures to construct and maintain. There can be no assurance that recovery through rates would be authorized, particularly given the magnitude of any potential impact on customer rates, which at this time cannot be predicted with certainty. Idaho Power also cannot predict the requirements that might be imposed during the relicensing process, the economic impact of those requirements, or whether a new multi-year license will ultimately be issued. Imposition of onerous conditions in the relicensing process could result in Idaho Power incurring significant capital expenditures, increase operating costs, and reduce hydroelectric generation, which could reduce earnings and cash flows.

IDACORP, Idaho Power, and their subsidiaries are subject to costs and other effects of legal and regulatory proceedings, settlements, investigations, and claims. From time to time in the normal course of business, IDACORP, Idaho Power, and their subsidiaries are subject to various regulatory proceedings, lawsuits, and claims that could result in adverse judgments, settlements, fines, penalties, injunctions, or other relief. These matters are subject to a number of uncertainties, and as a result management is often unable to predict the outcome of a matter. The final resolution of matters in which IDACORP, Idaho Power, or their subsidiaries are involved could require that they incur costs in a range of amounts that could have an adverse effect on their cash flows and results of operations. Similarly, the terms of resolution could require the companies to change their business practices and procedures, which could also have an adverse effect on their cash flows, financial positions, or results of operations.

IDACORP, IDACORP Energy, and Idaho Power are involved in a number of proceedings, including proceedings arising from the California energy crisis and the energy shortages, high prices, and blackouts in the western United States during 2000 and 2001, and a refund proceeding affecting sellers of wholesale power in the spot market in the Pacific Northwest. Idaho Power may also be subject to costs and other effects of additional legal claims, actions, and complaints, including those related to the Jim Bridger, Valmy, and Boardman coal-fired plants, in which Idaho Power holds an ownership interest. For instance, in September 2010 the Environmental Protection Agency issued a Notice of Violation to Portland General Electric Company, the majority owner of the Boardman plant, alleging violations of the New Source Performance Standards and operating permit requirements under the Clean Air Act as a result of prior modifications made to the plant. Private parties have also brought tort actions against companies relating to their alleged contribution to climate change, including claims relating to the Jim Bridger and Boardman power plants. If IDACORP, Idaho Power, or their subsidiaries are required to make payments in connection with any legal or regulatory proceeding, settlement, investigation, or claim, earnings and cash flows could be negatively affected.

As a holding company, IDACORP does not have its own operating income and must rely on the upstream cash flows from its subsidiaries to pay dividends and make debt payments. IDACORP is a holding company with no significant operations of its own, and its primary assets are shares or other ownership interests of its subsidiaries, primarily Idaho Power. Consequently, IDACORP’s ability to pay dividends and to service its debt is dependent upon dividends and other payments received from its subsidiaries. IDACORP’s subsidiaries are separate and distinct legal entities and have no obligation to pay any amounts to IDACORP, whether through dividends, loans, or other payments. The ability of IDACORP’s subsidiaries to pay dividends or make distributions to IDACORP depends on several factors, including each subsidiaries’ actual and projected earnings and cash flow, capital requirements and general financial condition, regulatory restrictions, covenants contained in credit facilities to which they are parties, and the prior rights of holders of their existing and future first mortgage bonds and other debt or equity securities. Further, the amount and payment of dividends is at the discretion of the board of directors, which reviews the appropriateness of dividends in light of current and long-term financial position and results of operations, capital requirements, rating agency requirements, contractual and regulatory restrictions, legislative and regulatory developments affecting the electric utility industry in general and Idaho Power in particular, competitive conditions, and any other factors the board of directors deems relevant. Any of these factors may result in a reduction or cessation of dividends. See Part II, Item 5 - "Market for Registrant's Common Equity, Related Stockholder Matters, and Issuer Purchases of Equity Securities" of this report for a description of restrictions on IDACORP's and Idaho Power's payment of dividends.

A downgrade in IDACORP’s and Idaho Power’s credit ratings could affect the companies’ ability to access capital, increase their cost of borrowing, and require the companies to post collateral with transaction counterparties. Access to capital markets is important to Idaho Power's ability to operate and to complete its capital projects, including its current and planned generation and transmission projects. Credit rating agencies periodically review the corporate credit ratings and long-term ratings of IDACORP and Idaho Power, and these ratings impact access to, and the cost of, borrowing. IDACORP and Idaho Power also have borrowing arrangements that rely on the ability of the banks to fund loans or support commercial paper, a principal source of short-term financing. Downgrades of IDACORP’s or Idaho Power’s credit ratings, or those affecting relationship banks, could limit the companies' ability to access capital, including the commercial paper markets, require the companies to pay a higher interest rate on their debt, and require the companies to post additional performance assurance collateral with transaction counterparties.

Volatility in the financial markets, or denial of regulatory authority to issue debt or equity securities, may negatively affect IDACORP's and Idaho Power's ability to access capital and/or increase their cost of borrowing, or result in losses on investments. IDACORP and Idaho Power require liquidity to pay operating expenses and principal of, and interest on, debt and to finance capital expenditures not satisfied by cash flows from operations. Financial markets have in recent years experienced extreme volatility and disruption, generally resulting in a decrease in the availability of liquidity and credit for borrowers. In a volatile credit environment, one or more of the participating banks in IDACORP's and Idaho Power's credit facilities may default on their obligations to make loans under, or withdraw from, the credit facilities, or IDACORP's and Idaho Power's access to capital may otherwise be inhibited. In addition, at times Idaho Power has a relatively large balance of short-term investments. Volatility in the financial markets may result in a lack of liquidity for short-term investments and declines in value of some investments. The occurrence of any of these events could affect Idaho Power's ability to execute its business plan and adversely affect IDACORP's and Idaho Power's earnings, liquidity, and financial condition. Further, Idaho Power is required to obtain regulatory approval in Idaho, Oregon, and Wyoming in order to borrow money or to issue securities and is therefore dependent on the public utility commissions of those states to issue favorable orders in a timely manner to permit them to finance their operations. Notably, without additional approval from those commissions, the aggregate amount of short-term borrowings by Idaho Power at any one time outstanding may not exceed $450 million.

National and regional economic conditions, in conjunction with increased electric rates, may cause increased late payments and uncollectible customer accounts, or reduce energy consumption, which would reduce earnings and cash flows. Beginning in 2008, economic conditions in Idaho Power's service area have been relatively weak. Unemployment rates are high relative to historic unemployment levels and customer growth has been slow relative to prior years. These factors may reduce the amount of energy Idaho Power's customers consume; result in a loss of customers; increase the likelihood and prevalence of late payments and uncollectible accounts, and reduce the customer growth rate. A resulting decrease in overall customer usage or collections may reduce revenues and earnings.

Changes in tax laws and regulations, or differing interpretation or enforcement of applicable laws by the Internal Revenue Service or other taxing jurisdictions, could have a material adverse impact on IDACORP's or Idaho Power's financial condition. IDACORP and Idaho Power must make judgments and interpretations about the application of the law when determining the provision for taxes. The companies' tax obligations include income, real estate, public utility, municipal, sales and use, business and occupation, and employment-related taxes and ongoing issues related to these taxes. These judgments may include reserves for potential adverse outcomes regarding tax positions that may be subject to challenge by taxing authorities. For instance, recent income tax method changes had a significant impact on financial results in 2011. The outcome of ongoing and future income tax proceedings could differ materially from the amounts IDACORP and Idaho Power record prior to conclusion of those proceedings, and the difference could reduce IDACORP's and Idaho Power's earnings and cash flows. Further, in some instances the treatment from a ratemaking perspective of any tax benefits could be different than IDACORP or Idaho Power anticipate or request from applicable state regulatory commissions. The Idaho Public Utilities Commission or Oregon Public Utility Commission could, for instance, determine that all or a portion of any benefits resulting from tax-related projects be shared with customers in the form of reduced rates or otherwise, which may reduce revenue, earnings, and cash flows.

Employee workforce factors could increase costs and reduce earnings. Idaho Power is subject to workforce factors, including loss or retirement of key personnel, availability of qualified personnel, an aging workforce, and impacts of efforts to organize workforce, including the possible unionization of one or more segments of the workforce. Idaho Power's operations require a skilled workforce to perform specialized, complex utility functions. Idaho Power expects that a significant portion of its skilled workforce will be retiring, at a rate higher than Idaho Power's historical rate, within the next ten years, which places demand on Idaho Power to attract and retain skilled workers. Without a skilled workforce, Idaho Power's ability to provide quality service to its customers and meet regulatory requirements will be challenged and could affect earnings. Also, the costs associated with attracting and retaining appropriately qualified employees to replace an aging and skilled workforce could reduce earnings and cash flows.

Acts or threats of terrorism, cyber attacks, security breaches, and other acts of individuals or groups seeking to disrupt Idaho Power's operations, or the businesses of third parties, could result in reduced revenues and increased costs. Idaho Power's generation and transmission facilities are potential targets for terrorist acts and threats, as well as cyber attacks and other disruptive activities of individuals or groups. Some of Idaho Power's facilities are deemed critical infrastructure, in that incapacity or destruction of the facilities could have a debilitating impact on security, reliability or operability of the bulk electric power system, national economic security, national public health or safety, or any combination of those matters. The possibility that infrastructure facilities, such as generation facilities and electric transmission facilities, would be direct targets of, or indirect casualties of, an act of terror or cyber attack (whether originating internally or externally) may affect Idaho Power's operations by limiting the ability to generate, purchase, or transmit power and by delaying the development and construction of new generating and transmission facilities and capital improvements to existing facilities. These events, and governmental actions in response, could result in a material decrease in revenues and significant additional costs to repair and insure Idaho Power's assets, and could further adversely affect Idaho Power's operations by contributing to disruption of supplies and markets for natural gas or coal used to fuel gas-fired or coal-fired power plants. Because generation and transmission are part of an interconnected system, Idaho Power faces the risk of possible loss of business due to a disruption caused by the impact of an event on the interconnected system. The events could also impair IDACORP's and Idaho Power's ability to raise capital by contributing to financial instability and lower economic activity. Further, the implementation of security guidelines and measures has resulted in and is expected to continue to result in increased compliance costs.

In the normal course of business, Idaho Power collects, processes, and retains sensitive and confidential customer and proprietary information, and operates systems that directly impact the availability of electric power and the transmission of electric power in the electric grid. Idaho Power operates in a highly regulated industry that requires the continued operation of sophisticated information technology systems and network infrastructure. Despite the security measures in place, Idaho Power's facilities and systems, and those of third-party service providers, could be vulnerable to security breaches, data leakage, or other similar events that could interrupt operations, resulting in a shutdown of service and exposing Idaho Power to liability. Those breaches and events may result from acts of Idaho Power employees, contractors, or third parties. If Idaho Power's technology systems were to fail or be breached and Idaho Power were unable to recover the systems and/or data in a timely manner, Idaho Power may be unable to fulfill critical business functions. Also, confidential and proprietary business, employee, or customer information could be compromised, exposing Idaho Power to liability and causing business disruptions, which could have a material adverse effect on Idaho Power's operations and IDACORP's and Idaho Power's financial results. The implementation of security guidelines and measures and maintenance of insurance, to the extent available, addressing such activities could increase costs and impact financial results. In addition, these types of events could require significant management attention and resources, and could adversely affect IDACORP's and Idaho Power's reputation among customers and the public.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Idaho Power's system is comprised of 17 hydroelectric generating plants located in southern Idaho and eastern Oregon, two natural gas-fired plants located in southern Idaho, and interests in three coal-fired steam electric generating plants located in Wyoming, Nevada, and Oregon. Idaho Power is also constructing a natural gas-fired combined cycle power plant in Idaho with a summer nameplate capacity of 300 MW, expected to be ready for commercial operation by July 1, 2012. As of December 31, 2011, the system also includes approximately 4,828 pole miles of high-voltage transmission lines, 23 step-up transmission substations located at power plants, 24 transmission substations, 10 switching stations, 228 energized distribution substations (excluding mobile substations and dispatch centers), and approximately 26,714 pole miles of distribution lines.

Idaho Power holds FERC licenses for all of its hydroelectric projects that are subject to federal licensing. These projects and the other generating stations and their nameplate capacities are listed below.

Project	Nameplate Capacity (kW)	License Expiration
Hydroelectric Developments:		
Properties subject to federal licenses:		
Lower Salmon	60,000	2034
Bliss	75,000	2034
Upper Salmon	34,500	2034
Shoshone Falls	12,500	2034
CJ Strike	82,800	2034
Upper Malad - Lower Malad	21,770	2035
Brownlee - Oxbow - Hells Canyon	1,166,900	2005 [1]
Swan Falls	27,170	2010 [1]
American Falls	92,340	2025
Cascade	12,420	2031
Milner	59,448	2038
Twin Falls	52,897	2040
Other Hydroelectric:		
Clear Lakes - Thousand Springs	11,300	
Total Hydroelectric	1,709,045	
Steam and Other Generating Plants:		
Jim Bridger (coal-fired) [2]	770,501	
Valmy (coal-fired) [2]	283,500	
Boardman (coal-fired) [2][3]	64,200	
Danskin (gas-fired)	270,900	
Salmon (diesel-internal combustion)	5,000	
Bennett Mountain (gas-fired)	172,800	
Total Steam and Other	1,566,901	
Total Generation	3,275,946	

(1) Licensed on an annual basis while the application for a new multi-year license is pending.

(2) Idaho Power's ownership interests are 33 percent for Jim Bridger, 50 percent for Valmy, and 10 percent for Boardman. Amounts shown represent Idaho Power's share.

(3) Pursuant to an Oregon Environmental Quality Commission plan and associated rules, the Boardman power plant is scheduled for cessation of coal-fired operations on December 31, 2020.

Relicensing of Idaho Power's hydroelectric projects is discussed in Part II, Item 7 - "MD&A – Regulatory Matters – Relicensing of Hydroelectric Projects."

Idaho Power owns all of its interests in principal plants and other important units of real property, except for portions of certain projects licensed under the FPA and reservoirs and other easements. Idaho Power's property is also subject to the lien of its Mortgage and Deed of Trust and the provisions of its project licenses. In addition, Idaho Power's property is subject to minor defects common to properties of such size and character that do not materially impair the value to, or the use by, Idaho Power of such properties. Idaho Power considers its properties to be well-maintained and in good operating condition.

IERCo owns a one-third interest in BCC and coal leases near the Jim Bridger generating plant in Wyoming from which coal is mined and supplied to the plant. Ida-West holds 50 percent interests in nine operating hydroelectric plants with a total generating capacity of 45 MW. These plants are located in Idaho and California.

ITEM 3. LEGAL PROCEEDINGS

Refer to Note 10 – "Contingencies" to IDACORP's and Idaho Power's consolidated financial statements included in this report.

ITEM 4. MINE SAFETY DISCLOSURES

Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 CFR 229.104) is included in Exhibit 95.1 of this report.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS, AND ISSUER PURCHASES OF EQUITY SECURITIES

IDACORP's common stock, without par value, is traded on the New York Stock Exchange (NYSE). On February 17, 2012, there were 12,508 holders of record of IDACORP common stock and the closing stock price was $41.85 per share. The outstanding shares of Idaho Power's common stock, $2.50 par value, are held by IDACORP and are not traded. IDACORP became the holding company of Idaho Power on October 1, 1998.

The amount and timing of dividends paid on IDACORP's common stock are within the sole discretion of IDACORP's board of directors. The board of directors reviews the dividend rate quarterly to determine its appropriateness in light of IDACORP's current and long-term financial position and results of operations, capital requirements, rating agency requirements, contractual and regulatory restrictions, legislative and regulatory developments affecting the electric utility industry in general and Idaho Power in particular, competitive conditions, and any other factors the board of directors deems relevant. The ability of IDACORP to pay dividends on its common stock is dependent upon dividends paid to it by its subsidiaries, primarily Idaho Power. At its November 2011 meeting, the IDACORP board of directors adopted a dividend policy for IDACORP that provides for a target long-term dividend payout ratio of between 50 and 60 percent of sustainable IDACORP earnings, with the flexibility to achieve that payout ratio over time and to adjust the payout ratio or to deviate from the target payout ratio from time to time based on the various factors that drive the board of director's dividend decisions. Notwithstanding the dividend policy adopted by the IDACORP board of directors, the dividends IDACORP pays remain in the discretion of the board of directors who, when evaluating the dividend amount, will take into account the foregoing factors, among others.

A covenant under IDACORP's credit facility and Idaho Power's credit facility described in Part II, Item 7 - "MD&A – Liquidity and Capital Resources - Financing Programs – Credit Facilities" requires IDACORP and Idaho Power to maintain leverage ratios of consolidated indebtedness to consolidated total capitalization, as defined in the respective credit facilities, of no more than 65 percent at the end of each fiscal quarter.

Idaho Power's Revised Code of Conduct approved by the IPUC on April 21, 2008, states that Idaho Power will not pay any dividends to IDACORP that will reduce Idaho Power's common equity capital below 35 percent of its total adjusted capital without IPUC approval. Idaho Power's ability to pay dividends on its common stock held by IDACORP and IDACORP's ability to pay dividends on its common stock are limited to the extent payment of such dividends would violate the covenants or Idaho Power's Code of Conduct. At December 31, 2011, the leverage ratios for IDACORP and Idaho Power were 48 percent and 49 percent, respectively. Based on these restrictions, IDACORP's and Idaho Power's dividends were limited to $827 million and $723 million, respectively, at December 31, 2011. Idaho Power must obtain approval of the OPUC before it can directly or indirectly loan funds or issue notes or give credit on its books to IDACORP.

Idaho Power's articles of incorporation contain restrictions on the payment of dividends on its common stock if preferred stock dividends are in arrears. Idaho Power has no preferred stock outstanding. IDACORP and Idaho Power paid dividends of $60 million, $58 million, and $57 million in 2011, 2010, and 2009, respectively.

On January 19, 2012, IDACORP's board of directors voted to increase the quarterly dividend payable February 29, 2012 to

$0.33 per share of IDACORP common stock, from the prior dividend amount of $0.30 per share of IDACORP common stock. For additional information relating to IDACORP and Idaho Power dividends, including restrictions on IDACORP's and Idaho Power's payment of dividends, see Note 6 - “Common Stock” to the consolidated financial statements included in this report.

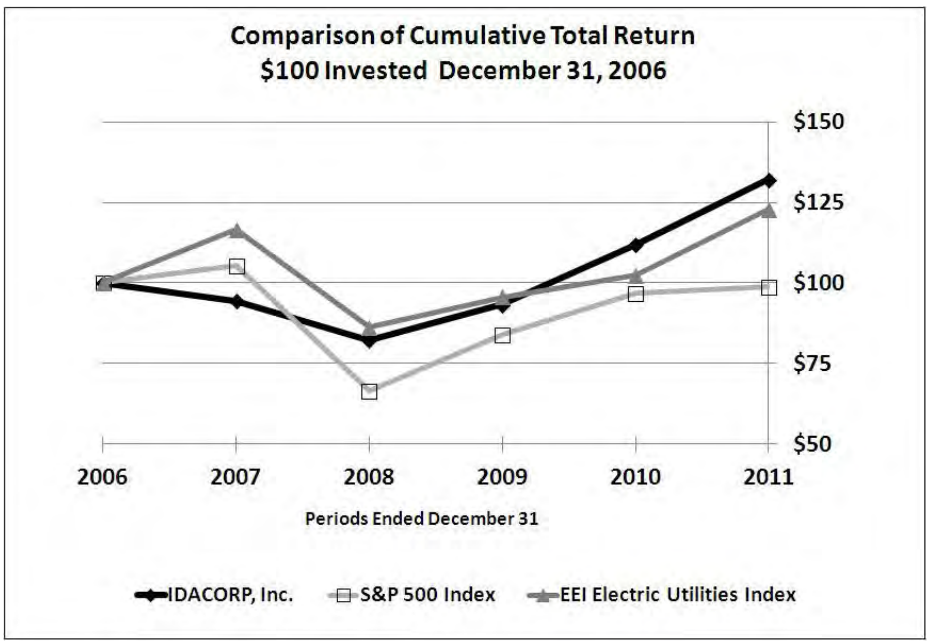
The following table shows the reported high and low sales price of IDACORP’s common stock and dividends paid for 2011 and 2010 as reported by the NYSE.

	2011			2010		
Quarter	**High**	**Low**	**Dividends paid per share**	**High**	**Low**	**Dividends paid per share**
1st	$ 38.72	$ 36.14	$ 0.30	$ 35.69	$ 29.98	$ 0.30
2nd	40.38	37.65	0.30	36.93	31.22	0.30
3rd	40.71	33.88	0.30	36.98	32.46	0.30
4th	42.66	37.26	0.30	37.76	35.46	0.30

IDACORP, Inc. did not repurchase any shares of its common stock during the fourth quarter of 2011.

Performance Graph

The following performance graph shows a comparison of the five-year cumulative total shareholder return for IDACORP common stock, the S&P 500 Index, and the Edison Electric Institute (EEI) Electric Utilities Index. The data assumes that $100 was invested on December 31, 2006, with beginning-of-period weighting of the peer group indices (based on market capitalization) and monthly compounding of returns.



Source: Bloomberg and EEI

	2006	2007	2008	2009	2010	2011
IDACORP	$ 100.00	$ 94.40	$ 82.12	$ 93.25	$ 111.75	$ 132.15
S&P 500	100.00	105.49	66.47	84.06	96.75	98.77
EEI Electric Utilities Index	100.00	116.56	86.37	95.62	102.34	122.80

The foregoing performance graph and data shall not be deemed “filed” as part of this Form 10-K for purposes of Section 18 of the Securities Exchange Act of 1934 or otherwise subject to the liabilities of that section and should not be deemed incorporated by reference into any other filing of IDACORP or Idaho Power under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent IDACORP or Idaho Power specifically incorporates it by reference into such filing.

ITEM 6. SELECTED FINANCIAL DATA

IDACORP, Inc.
SUMMARY OF OPERATIONS
(thousands of dollars, except per share amounts)

	2011	2010	2009	2008	2007
Operating revenues	$1,026,756	$1,036,029	$1,049,800	$ 960,414	$ 879,394
Operating income	164,248	198,670	203,583	190,667	152,078
Net income attributable to IDACORP, Inc.	166,693	142,798	124,350	98,414	82,272
Diluted earnings per share from continuing operations	3.36	2.95	2.64	2.17	1.86
Dividends declared per share	1.20	1.20	1.20	1.20	1.20
Financial Condition:					
Total assets	$4,960,609	$4,676,055	$4,238,727	$4,022,845	$3,653,308
Long-term debt (including current portion)	1,488,614	1,610,859	1,419,070	1,269,979	1,168,336
Financial Statistics:					
Times interest charges earned:					
Before tax [1]	2.35	2.65	2.88	2.47	2.35
After tax [2]	2.97	2.66	2.59	2.23	2.16
Book value per share [3]	$ 33.18	$ 31.01	$ 29.17	$ 27.76	$ 26.79
Market-to-book ratio [4]	128%	119%	110%	106%	131%
Payout ratio [5]	36%	41%	45%	55%	65%
Return on year-end common equity [6]	10.1%	9.3%	8.9%	7.6%	6.8%

The financial statistics listed above are calculated in the following manner:

[1] The sum of interest on long-term debt, other interest expense excluding AFUDC credits, and income before income taxes divided by the sum of interest on long-term debt and other interest expense excluding AFUDC credits.

[2] The sum of interest on long-term debt, other interest expense excluding AFUDC credits, and income from continuing operations divided by the sum of interest on long-term debt and other interest expense excluding AFUDC credits.

[3] Total equity, excluding non-controlling interests, at the end of the year divided by shares outstanding at the end of the year.

[4] The closing price of IDACORP stock on the last day of the year divided by the book value per share, which is described in footnote (3) above.

[5] Dividends paid per common share divided by diluted earnings per share.

[6] Net income attributable to IDACORP, Inc. divided by total equity, excluding non-controlling interests, at the end of the year.

Beginning January 1, 2009, noncontrolling interests (previously known as minority interests) were required to be classified as equity. IDACORP's consolidated financial statements reflect the reclassification of noncontrolling interests to equity for all periods presented.

ITEM 7. MANAGEMENT’S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

FORWARD-LOOKING STATEMENTS

In addition to the historical information contained in this report, this report contains (and oral communications made by IDACORP, Inc. and Idaho Power Company may contain) statements that relate to future events and expectations and, as such, constitute forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Any statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions, or future events or performance, often, but not always, through the use of words or phrases such as "anticipates," "believes," "estimates," "expects," "intends," "plans," "predicts," "projects," "may result," "may continue," or similar expressions, are not statements of historical facts and may be forward-looking. Forward-looking statements are not guarantees of future performance and involve estimates, assumptions, risks, and uncertainties. Actual results, performance, or outcomes may differ materially from the results discussed in the statements. In addition to any assumptions and other factors and matters referred to specifically in connection with such forward-looking statements, factors that could cause actual results or outcomes to differ materially from those contained in forward-looking statements include those factors set forth in Item 1A - "Risk Factors" of this report and the following important factors:

- the effect of regulatory decisions by the Idaho Public Utilities Commission, the Oregon Public Utility Commission, the Federal Energy Regulatory Commission, and other regulators affecting Idaho Power's ability to recover costs and/or earn a reasonable rate of return;
- variable hydrological conditions and over-appropriation of surface and groundwater in the Snake River basin, which can impact stream flows and the amount of generation from Idaho Power's hydroelectric facilities;
- the cost and availability of materials, fuel, and commodities, and their impact on Idaho Power's infrastructure costs, power costs, and ability to meet required loads, and their impact on the wholesale energy market in the western United States;
- costs and delays associated with construction and maintenance of power generation, transmission, and distribution facilities, including the inability to obtain required governmental permits and approvals, hydroelectric plant licenses under reasonable terms (and the costs resulting from conditions in such licenses), rights-of-way, and siting, and risks related to contracting, construction, and start-up;
- disruptions or outages of Idaho Power's generation or transmission systems or the western interconnected transmission system affecting Idaho Power's ability to deliver power to its customers and requiring the dispatch of more expensive generation resources or purchasing power, which may ultimately increase costs;
- increased costs associated with the legislatively mandated purchase of intermittent power, such as wind, at above-market rates, and the costs and other challenges of integrating intermittent power sources into Idaho Power's resource portfolio;
- population growth and changes in residential, commercial, and industrial growth and demographic patterns within Idaho Power's service area, the loss or change in the business of significant customers, and the associated impact on loads and load growth;
- the continuing effects of the weak economy in Idaho Power's service territory and elsewhere, including decreased demand for electricity, reducing revenue from sales of excess energy during periods of low wholesale market prices, impaired financial soundness of vendors and service providers, and elevated levels of uncollectible customer accounts;
- changes in and costs of compliance with laws, regulations, and policies relating to the environment, natural resources, and endangered species and the adoption of laws and regulations addressing greenhouse gas emissions, global climate change, and energy policies intended to mitigate carbon dioxide, mercury, and other emissions;
- global climate change and regional or national weather variations, which affect customer demand and hydroelectric generation and can impact the ability and cost to procure adequate supplies of natural gas, coal, or purchased power to serve customers;
- inclement weather and other natural phenomena such as earthquakes, floods, droughts, lightning, wind, and fire, which, in addition to affecting customer demand for power, could significantly affect the ability and cost to procure adequate supplies of fuel or power to serve customers, and could increase the costs to repair and maintain Idaho Power's generating facilities, transmission and distribution systems, and other infrastructure;

- transaction risks, including increases in costs, associated with Idaho Power's energy commodity and other derivative instruments, the failure of Idaho Power's energy risk management policies to work as intended, exposure to counterparty credit risk, and potential higher costs of hedging activities due to new regulations pertaining to swaps and derivatives;
- wholesale market conditions, including availability of power on the spot market and the ability to enter into commodity financial hedges with creditworthy counterparties, and the cost of those hedges, which may affect the prices Idaho Power must pay for power as well as the prices at which Idaho Power can sell any excess power;
- deteriorating values in the equity markets, changes in interest rates and credit spreads, reductions in demand for investment-grade commercial paper, inflation, and other financial market conditions, as well as changes in government regulations, which affect, among other things, the cost of capital and the ability to access the capital markets, indebtedness obligations, and the amount and timing of required contributions to benefit plans;
- failure of Idaho Power to comply with state and federal laws, policies, and regulations, including new interpretations and enforcement initiatives by regulatory and oversight bodies, including, but not limited to, the Federal Energy Regulatory Commission, the North American Electric Reliability Corporation, the Western Electricity Coordinating Council, the U.S. Environmental Protection Agency, and Idaho and Oregon state regulatory commissions, which may result in penalties, increase the cost of compliance, the nature and extent of investigations and audits, and costs of remediation;
- the cost and outcome of litigation, dispute resolution, and regulatory proceedings, and penalties, settlements, or awards that influence the companies' business and operations;
- reductions in credit ratings, which could adversely impact access to capital markets and would require the posting of additional collateral to counterparties pursuant to existing power purchase and credit arrangements;
- the ability to obtain debt and equity financing or refinance existing debt when necessary or on favorable terms, which can be affected by factors such as credit ratings, volatility in the financial markets, the companies' financial performance, and other economic conditions;
- whether the companies will be able to continue to pay dividends under the terms of their respective financing and credit agreements and regulatory limitations, and whether the companies' boards of directors will continue to declare common stock dividends based on the boards of directors’ periodic consideration of factors ordinarily affecting dividend policy, such as current and prospective financial condition, earnings and liquidity, prospective business conditions, regulatory factors, and restrictions in applicable agreements;
- changes in tax laws or related regulations or new interpretations of applicable law by the Internal Revenue Service or state and local taxing jurisdictions, and the availability and use by IDACORP or Idaho Power of tax credits;
- employee workforce factors, including unionization or the attempt to unionize all or part of the companies' workforce, and the ability to adjust the labor cost structure to changes in growth within Idaho Power's service territory;
- the failure of information systems or the failure to secure information system data, security breaches, or the direct or indirect effect on the companies' business resulting from the occurrence of cyber attacks, terrorist incidents or the threat of terrorist incidents, and acts of war;
- adoption of or changes in accounting policies, principles, or estimates, including the potential adoption of all or a portion of International Financial Accounting Standards; and
- new accounting or Securities and Exchange Commission or New York Stock Exchange requirements, or new interpretations of existing requirements.

Any forward-looking statement speaks only as of the date on which such statement is made. New factors emerge from time to time and it is not possible for management to predict all such factors, nor can it assess the impact of any such factor on the business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement. IDACORP and Idaho Power disclaim any obligation to update publicly any forward-looking information, whether in response to new information, future events, or otherwise, except as required by applicable law.

INTRODUCTION

In Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A), the general financial condition and results of operations for IDACORP, Inc. and its subsidiaries (collectively, IDACORP) and Idaho Power Company and its subsidiary (collectively, Idaho Power) are discussed. While reading the MD&A, please refer to the accompanying consolidated financial statements of IDACORP and Idaho Power.

IDACORP is a holding company formed in 1998 whose principal operating subsidiary is Idaho Power. IDACORP's common stock is listed and trades on the New York Stock Exchange under the trading symbol "IDA." Idaho Power is an electric utility with a service territory covering approximately 24,000 square miles in southern Idaho and eastern Oregon. Idaho Power provided electric service to approximately 496,000 general business customers as of December 31, 2011. As a regulated utility, many of Idaho Power's fundamental business decisions are subject to the approval of governmental agencies. Idaho Power is under the retail jurisdiction (as to rates, service, accounting, and other general matters of utility operation) of the Idaho Public Utilities Commission (IPUC) and the Oregon Public Utility Commission (OPUC), which determine the rates that Idaho Power charges to its general business customers. Also, as a public utility under the Federal Power Act, Idaho Power has authority to charge market-based rates for wholesale energy sales under its Federal Energy Regulatory Commission (FERC) tariff and to provide transmission services under its FERC open access transmission tariff (OATT). Idaho Power uses general rate cases, cost adjustment mechanisms, and subject-specific filings to recover its costs of providing service and the costs of its energy efficiency and demand-side resources programs, and to seek to earn a return on investment.

Idaho Power generates revenues and cash flows primarily from the sale and distribution of electricity to customers in its Idaho and Oregon service territories, as well as from the wholesale sale and transmission of electricity. Idaho Power's revenues and income from operations are subject to fluctuations during the year due to the impacts of seasonal weather conditions on demand for electricity, availability of water for hydroelectric generation, price changes, customer usage patterns (which are affected in large part by the condition of the local economy), and the availability and price of purchased power and fuel. Idaho Power is a dual peaking utility that typically experiences its highest retail energy sales during the summer irrigation and cooling season, with a lower peak in the winter that generally results from heating demand. IDACORP's and Idaho Power's financial condition is also affected by regulatory decisions, through which Idaho Power seeks to recover its costs on a timely basis, and to earn an authorized return on investment, and by the ability to obtain financing through the issuance of debt and/or equity securities.

IDACORP's other subsidiaries include IDACORP Financial Services, Inc. (IFS), an investor in affordable housing and other real estate investments; Ida-West Energy Company, an operator of small hydroelectric generation projects that satisfy the requirements of the Public Utility Regulatory Policies Act of 1978 (PURPA); and IDACORP Energy, a marketer of energy commodities, which wound down operations in 2003. Idaho Power is the parent of Idaho Energy Resources Co. (IERCo), a joint venturer in Bridger Coal Company (BCC), which mines and supplies coal to the Jim Bridger generating plant owned in part by Idaho Power.

EXECUTIVE OVERVIEW

Overview of 2011 Financial Results

IDACORP's earnings were $3.36 per diluted share for the year ended December 31, 2011 compared to $2.95 and $2.64 per diluted share in 2010 and 2009, respectively. IDACORP's earnings in 2011 were impacted by the approval of a tax method change that allowed Idaho Power to recognize during 2011 $56.9 million in tax benefits relating to tax years 2009 and prior. This tax benefit, combined with the results of ongoing operations, triggered sharing mechanisms in Idaho that reduced operating income by $47.4 million, reflecting earnings to be shared with Idaho customers to reduce rates. In addition, 2011 results include the full-year impact of base rate increases implemented in 2010, higher electricity sales volumes, and lower PCA rates.

2011 Accomplishments and 2012 Challenges and Areas of Emphasis

IDACORP's business strategy emphasizes Idaho Power as IDACORP's core business. Idaho Power has a three-part strategy of responsible planning, responsible development and protection of resources, and responsible energy use to ensure adequate energy supplies. This strategy is described in Part I, Item 1 - "Business" of this report. Examples of Idaho Power's achievements during 2011 under its three-part business strategy include:

- execution of Idaho Power's purposeful regulatory strategy, which resulted in settlement of Idaho Power's 2011 Idaho general rate case with the IPUC (including a base rate increase effective January 1, 2012), a June 1, 2011 base rate

increase for recovery of the Idaho-allocated portion of Idaho Power's cash contributions to its defined benefit pension plan, and several other positive regulatory decisions;
- execution of a settlement agreement with the IPUC extending through 2014 Idaho Power's ability to amortize additional accumulated deferred investment tax credits (ADITC) to help achieve a minimum annual return on year-end equity in the Idaho jurisdiction (Idaho ROE) of 9.5 percent;
- significant progress toward cost-sharing agreements with other parties for the permitting of the Boardman-to-Hemingway and Gateway West 500-kV transmission projects, which were ultimately executed in January 2012;
- completion of deployment of smart meters to substantially all customers;
- continued progress on the construction of the Langley Gulch power plant;
- approval by the U.S. Congress Joint Committee on Taxation (Joint Committee) of a tax method change for uniform capitalization, resulting in a significant increase in net income relative to 2010; and
- ranking in the top quartile of the 120 largest utilities in the country for customer satisfaction in the J.D. Power and Associates 2011 Electric Utility Residential Customer Satisfaction Study.

During 2012, IDACORP's and Idaho Power's management will continue to focus on and implement the companies' three-part strategy. Notable matters that the companies expect will require management's focus and attention in 2012 include:

- completion of construction and commencement of commercial operations of the Langley Gulch power plant, and timely and adequate rate recovery of costs for the plant;
- continued efforts toward permitting of the Boardman-to-Hemingway and Gateway West transmission projects;
- seeking a positive outcome in proceedings at the IPUC relating to the pricing models and other terms of PURPA power purchase agreements;
- seeking methods for the integration of intermittent power sources and anticipated increases in intermittent wind generation, which Idaho Power believes could have an adverse impact on system reliability and functionality and on customer rates;
- obtaining IPUC authorization to include Idaho Power's FCA as a permanent component of rates;
- implementation of a new customer and billing system; and
- continued work toward resolution of issues relating to relicensing of Idaho Power's hydroelectric projects, including the Hells Canyon Complex.

Overview of General Factors and Trends Affecting Results of Operations and Financial Condition

IDACORP's and Idaho Power's results of operations and financial condition are affected by regulatory, economic, and other factors, many of which are described below.

Emphasis on Regulatory Cost Recovery: The prices that Idaho Power is authorized to charge for its electric service is a major factor in determining IDACORP's and Idaho Power's results of operations and financial condition. Because of the significant impact of ratemaking decisions on Idaho Power's business and financial condition, the company continues to focus on timely recovery of its costs through filings with the company's regulators. Effective implementation of Idaho Power's purposeful regulatory strategy is particularly important in an economic climate that puts pressure on regulators to limit rate increases or otherwise take actions to limit the potential adverse impact of rates on customers. Regulatory developments that IDACORP and Idaho Power expect to have an impact on their future results, each of which is discussed in more detail under "Regulatory Matters" in this MD&A or in Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report, include the following:

- *Idaho 2011 General Rate Case and Settlement* - On December 30, 2011, the IPUC approved a settlement stipulation resolving most of the issues in the general rate case. The settlement stipulation provides for a 7.86 percent authorized rate of return on an Idaho-jurisdictional rate base of approximately $2.36 billion. The settlement stipulation results in a $34 million, or 4.07 percent average, increase in Idaho Power's annual Idaho-jurisdictional base rate revenues, effective January 1, 2012.

- *Extension of Certain Provisions of the January 2010 Settlement Agreement* - On January 13, 2010, the IPUC approved a settlement agreement among Idaho Power, several of Idaho Power’s customers, the IPUC Staff, and others, in connection with a general rate case. The settlement agreement included, among other items: (a) a provision to share with Idaho customers 50 percent of any Idaho-jurisdiction earnings in excess of a 10.5 percent Idaho ROE in any calendar year from 2009 to 2011; and (b) a provision to allow the additional amortization of ADITC if Idaho Power's actual Idaho ROE was below 9.5 percent in any calendar year from 2009 to 2011. The sharing and amortization provisions of the January 2010 settlement agreement expired on December 31, 2011. On December 27, 2011, the

IPUC issued an order approving a settlement stipulation providing for an extension through 2014, with modifications, of those two provisions of the January 2010 settlement agreement. The extension provides for up to $45 million of additional amortization of ADITC through 2014, with certain annual limits, and additional sharing of annual earnings in excess of specified Idaho ROEs. In consideration for the extension, the settlement stipulation provided that Idaho Power would allocate to customers (as a reduction to Idaho Power's pension regulatory asset) 75 percent of Idaho Power's share of 2011 Idaho-jurisdictional earnings over a 10.5 percent Idaho ROE. After the combined effect of the 50 percent sharing mechanism in the January 2010 settlement agreement and the December 2011 settlement order that provided for additional sharing, Idaho Power retained 12.5 percent of Idaho-jurisdiction earnings exceeding a 10.5 percent Idaho ROE.

- *Idaho PCA Orders* - In both its Idaho and Oregon jurisdictions, Idaho Power has power cost adjustment (PCA) mechanisms that address the volatility of power supply costs and provide for annual adjustments to the rates charged to retail customers. The Idaho PCA mechanism compares Idaho Power's actual net power supply costs to net power supply costs currently being recovered in retail rates, with most of the variance between these two amounts deferred for future recovery from, or refund to, customers. On May 31, 2011, the IPUC approved a $40.4 million PCA decrease, effective June 1, 2011. This followed a May 28, 2010 IPUC order approving a $146.9 million PCA decrease, effective June 1, 2010. These PCA rate decreases were offset by increases in power supply costs in base rates and deferrals and amortization under the PCA mechanism, resulting in a relatively small impact on earnings.

- *Idaho FCA Mechanism* - The FCA is designed to remove Idaho Power's disincentive to invest in energy efficiency programs by separating (or decoupling) the recovery of fixed costs from the variable kilowatt-hour charge and linking it instead to a set amount per customer. The FCA began as a pilot program in 2007 and expired on December 31, 2011. On October 19, 2011, Idaho Power filed an application with the IPUC requesting that the FCA pilot program become permanent. As of the date of this report, a determination and order from the IPUC as to the future of the FCA is pending.

- *Oregon 2011 General Rate Case* - On July 29, 2011, Idaho Power filed a general rate case for its Oregon jurisdiction with the OPUC, requesting a $5.8 million increase in annual Oregon jurisdictional revenues. On February 1, 2012, Idaho Power, the OPUC Staff, and other interested parties executed and filed a partial settlement stipulation with the OPUC that provides for a return on equity of 9.9 percent and an overall rate of return of 7.757 percent. If the OPUC approves the stipulation, Idaho Power expects that new rates will become effective on March 1, 2012.

Economic Conditions and Customer Growth: Since 2008, economic conditions in Idaho Power's service territory have been relatively weak. Unemployment rates remain high compared to historical levels. After peaking at 10.0 percent in early 2011, the service area unemployment rate has fallen to 8.4 percent in December 2011, according to the Idaho Department of Labor. From 2001 through September 2008, the highest monthly unemployment rate in the service territory was 5.2 percent. The customer growth rate, while still positive, has been low relative to prior years. During 2011, the customer growth rate in Idaho Power's service territory was 0.7 percent. By comparison, for the 20-year period ending 2010 the average annual customer growth rate in Idaho Power's service territory was 2.7 percent. Economic conditions can impact consumer demand for electricity, collectability of accounts, the volume of off-system sales, and Idaho Power's need for purchased power. Management cannot predict the timing of, and pace at which, economic recovery may occur in Idaho Power's service territory. Idaho Power continues to manage costs while executing its three-part strategy of responsible planning, responsible development and protection of resources, and responsible energy use.

Weather Conditions and Associated Impacts: Weather conditions normally have a significant impact on energy sales and the seasonality of those sales. Relatively low and high temperatures result in greater energy usage for heating and cooling, respectively. During the agricultural growing season, which in large part occurs during the second and third quarters of each calendar year, irrigation customers use electricity to operate irrigation pumps. A 1.6 percent increase in energy usage by Idaho Power customers during 2011 compared to 2010 is largely attributable to below average temperatures in the winter months offset by above average precipitation in the springtime, resulting in increased heating unit load and lower use of irrigation pumps.

Idaho Power's hydroelectric facilities comprise approximately one-half of Idaho Power's nameplate generation capacity. The actual availability of hydroelectric power depends on the amount of snow pack in the mountains upstream of Idaho Power's hydroelectric facilities, reservoir storage, springtime snow pack run-off, base flows in the Snake River, spring flows, rainfall, water leases and other water rights, and other weather and stream flow considerations. At the date of this report, Idaho Power expects hydroelectric generation during 2012 in the range of 7.5 to 9.5 million MWh, based on reservoir storage levels and forecasted weather conditions as of February 12, 2012, compared to 10.9 million MWh in 2011 and 7.3 million MWh in 2010.

Median annual hydroelectric generation is 8.6 million MWh. Due largely to favorable hydroelectric generation conditions, hydroelectric generation comprised 69 percent of Idaho Power's total system generation during 2011 and 51 percent during 2010. Where favorable hydroelectric generating conditions exist for Idaho Power, they also may be abundant for other Pacific Northwest hydroelectric facility operators, thus increasing the available supply of lower-cost power and depressing regional wholesale market prices, which impacts the revenue Idaho Power receives from off-system sales of its excess power. Average wholesale power prices per MWh for sales for resale were down 29 percent in 2011 relative to 2010.

Fuel and Purchased Power Expense: In addition to hydroelectric generation and power it purchases in the wholesale markets, Idaho Power relies significantly on coal and natural gas to fuel its generation facilities. Fuel costs are impacted by electricity sales volumes, the terms of contracts for fuel, Idaho Power's power generation capacity, the rate of expansion of alternative energy generation sources such as wind energy, the availability of hydroelectric generation resources, transmission capacity, energy market prices, and Idaho Power's hedging program for managing fuel costs.

For the year 2011, Idaho Power's weighted average fuel-related cost per MWh for its fossil fuel generation resources increased 17 percent relative to 2010, mainly due to the effect of lower generation output, which spreads fixed costs over lower output, and coal price increases. Notwithstanding the increase in fuel cost per MWh generated, total fuel expense decreased 18 percent relative to 2010, due to a decrease in output from fuel-fired power generating plants resulting from both the abundant hydroelectric generation and increased wind power obtained through mandated power purchases pursuant to PURPA. Looking ahead, operation of the Langley Gulch power plant that Idaho Power is currently constructing will increase Idaho Power's use of natural gas, and thus its exposure to volatility in natural gas prices.

Purchased power costs are impacted by the terms of contracts for purchased power, the rate of expansion of alternative energy generation sources such as wind energy, and wholesale energy market prices. Idaho Power is generally obligated to purchase power from PURPA generation projects at a specified price regardless of the then-current load demand or wholesale energy market prices. This increases the likelihood that Idaho Power will be required to reduce output from its lower-cost hydroelectric and fossil fuel-fired generation resources and may be required to sell in the wholesale power market the power it purchases from PURPA projects at a significant loss. Integration of intermittent, non-dispatchable resources into Idaho Power's portfolio also creates a number of operational risks, which Idaho Power is working to address.

The Idaho and Oregon PCA mechanisms mitigate in large part the potential adverse impacts of fluctuations in Idaho Power's power supply costs. Idaho Power also uses physical and financial forward contracts for both electricity and fuel in order to manage the risks relating to fuel and power price exposures.

Regulatory and Environmental Compliance Costs and Expenditures: Idaho Power is subject to extensive federal and state laws, policies, and regulations, as well as regulatory actions and audits. Compliance with these requirements directly influences Idaho Power's operating environment and may significantly increase Idaho Power's operating costs. Further, potential monetary and non-monetary penalties for a violation of applicable laws or regulations may be substantial. Accordingly, Idaho Power has in place numerous compliance policies and initiatives, and frequently evaluates, updates, and supplements those policies and initiatives. In particular, environmental laws and regulations may, among other things, increase the cost of operating power generation plants and constructing new facilities, require that Idaho Power install additional pollution control devices at existing generating plants, or require that Idaho Power shut down certain power generation plants. For instance, the Boardman coal-fired power plant, in which Idaho Power owns a 10 percent interest, was recently the subject of proceedings with Oregon regulators relating to the installation of costly emission controls and a cessation of coal-fired operations in 2020, and in September 2010 the U.S. Environmental Protection Agency (EPA) issued a Notice of Violation relating to the Boardman plant, alleging Clean Air Act (CAA) violations. As legislation and regulations concerning greenhouse gas emissions develop, Idaho Power will assess the potential impact on the costs to operate its power generation facilities, as well as the willingness or ability of power plant participants to fund any required pollution control equipment upgrades.

Other Notable Matters and Areas of Focus

Pension Plans: In 2010, Idaho Power contributed $60 million to its defined benefit pension plan, and in 2011 Idaho Power contributed an additional $18.5 million to the plan. On May 19, 2011, the IPUC authorized Idaho Power to increase its annual recovery and amortization of deferred pension costs from $5.4 million to $17.1 million. Idaho Power expects to make additional significant cash contributions to its defined benefit pension plan through at least 2016.

Water Management and Relicensing of Hydroelectric Projects: Because of Idaho Power's reliance on streamflow in the Snake River and its tributaries, Idaho Power participates in numerous proceedings and venues that may affect its water rights, seeking to preserve the long-term availability of its rights for use at its hydroelectric projects. Also, Idaho Power is involved in renewing federal licenses for the Hells Canyon Complex (HCC), its largest hydroelectric generation source, and the Swan Falls hydroelectric project. Relicensing involves numerous environmental issues and substantial costs. Idaho Power is working with the states of Idaho and Oregon, regulatory authorities, and interested parties to address concerns and take appropriate measures relating to the relicensing of Idaho Power's hydroelectric projects. Given the number of parties and issues involved, Idaho Power's relicensing costs have been and will continue to be substantial.

Transmission Projects: Idaho Power continues to focus on expansion of its transmission system in an effort to improve system reliability and resource adequacy through the proposed Boardman-to-Hemingway and Gateway West transmission projects. Construction of these projects cannot commence until all federal, state, and local regulatory requirements are met. In January 2012, Idaho Power entered into cost-sharing arrangements with third parties for the permitting phases of both projects. To further mitigate the risks associated with these projects, at least in part, Idaho Power plans to seek regulatory support for cost recovery from the IPUC and OPUC for the projects prior to construction.

2011 Tax-Related Projects: In September 2011, the U.S. Internal Revenue Service (IRS) notified Idaho Power that Idaho Power's uniform capitalization tax method agreement had been approved, resulting in the recognition of $56.9 million of its previously unrecognized tax benefits in 2011.

Summary of 2011 Financial Results

The following is a summary Idaho Power's net income, net income attributable to IDACORP, Inc., and IDACORP's earnings per diluted share for the years ended December 31, 2011, 2010, and 2009 (in thousands, except earnings per share amounts):

	Year Ended December 31,		
	2011	**2010**	**2009**
Idaho Power net income	$ 164,750	$ 140,634	$ 122,559
Net income attributable to IDACORP, Inc.	$ 166,693	$ 142,798	$ 124,350
Average outstanding shares – diluted (000’s)	49,558	48,340	47,182
IDACORP, Inc. earnings per diluted share	$ 3.36	$ 2.95	$ 2.64

The following table presents a reconciliation of net income attributable to IDACORP, Inc. for 2010 to 2011 (items are in millions and are before tax unless otherwise noted):

Net income attributable to IDACORP, Inc. - December 31, 2010			**$ 142.8**
Change in Idaho Power net income before taxes:			
Rate and other regulatory changes, including power cost, pension expense recovery, and fixed cost adjustment mechanisms		$ 26.3	
Changes in sales volumes		9.8	
Increased transmission service revenues		7.4	
Increased other operating and maintenance expenses:			
Pension and payroll related expenses (excluding pension impact of settlement stipulation below)		(17.2)	
Thermal plant expenses		(5.0)	
Other		(2.2)	
Increased depreciation expense		(3.9)	
Increased property taxes		(4.8)	
Other changes in operating income, net		1.1	
Increase in Idaho Power operating income prior to sharing mechanisms		11.5	
Additional pension expense as a result of settlement stipulation	(20.3)		
Decrease in revenues as a result of sharing mechanism	(27.1)		
Decrease in operating income as a result of sharing mechanisms		(47.4)	
Change in Idaho Power operating income		(35.9)	
Increase in AFUDC		11.6	
Other net decreases		(3.7)	
Increases due to tax method changes and related examination settlements		27.8	
Change in other income tax benefit		24.3	
Total increase in Idaho Power net income			24.1
Other net decreases (net of tax)			(0.2)
Net income attributable to IDACORP, Inc. - December 31, 2011			**$ 166.7**

Idaho Power net income increased by $24.1 million in 2011 compared to 2010, largely as a result of approval by the U.S. Congress Joint Committee on Taxation of the uniform capitalization method agreement with the IRS, which allowed for recognition in 2011 of $56.9 million of previously unrecognized tax benefits for tax years 2009 and prior. This benefit was partially offset by $47.4 million due to Idaho-jurisdictional sharing mechanisms.

The uniform capitalization method approval contributed to triggering of the sharing mechanism under Idaho Power's January 2010 settlement agreement with the IPUC and other parties. Under this sharing mechanism, Idaho Power recorded a $27.1 million reduction in revenues to be refunded to or to otherwise benefit customers, reflecting the equal sharing of Idaho-jurisdiction earnings in excess of a 10.5 percent Idaho ROE.

Additionally, Idaho Power recorded $20.3 million of additional pension expense as a result of an IPUC order approving a 2011 settlement stipulation that had been executed by Idaho Power, the IPUC Staff, and one large industrial customer of Idaho Power. The settlement stipulation provided that Idaho Power would allocate to customers 75 percent of Idaho Power's share of 2011 Idaho-jurisdictional earnings over a 10.5 percent Idaho ROE. As agreed to with the IPUC, this allocation was used to reduce Idaho Power's pension regulatory asset (reducing a portion of Idaho customers' future obligation), resulting in the corresponding recognition of additional pension expense.

Other items influencing the change in Idaho Power's operating income and annual earnings as compared to 2010 include:

- Several rate orders went into effect in 2010 and 2011 that impacted current year revenues and had a net positive impact on operating income. A June 1, 2010 base rate increase benefited 2011 with an additional five months of increased base rate revenue. A pension expense recovery rate increase occurred on June 1, 2010 and was further increased on June 1, 2011. Also included in the rate orders were PCA-related customer rate decreases on June 1 of both years. However, concurrent with each PCA rate decrease was a corresponding reduction in PCA expense. These rate changes, combined with lower power supply costs net of PCA mechanisms, improved operating income by approximately $26.3 million for the year.
- Increased sales volumes improved operating income by $9.8 million. Cooler temperatures early in the year contributed to an $8.0 million increase in electricity demand from residential customers, many of whom rely on electric power for heating systems during the winter months. This increase was partially offset by a $3.3 million decrease in irrigation revenues due to a wetter, cooler spring reducing the need to use irrigation pumps. A 17.7 percent increase in cooling degree days when compared with the prior year, particularly an increase in temperature in the late summer months, drove the remaining increase.
- Transmission system revenues, a component of other revenues, increased $7.4 million, principally resulting from increases in wheeling services attributable to increases in FERC transmission rates that took effect on October 1, 2010 and 2011, and from other facility rental increases.
- O&M expenses increased, primarily due to an $11.5 million increase in pension expense associated with the pension recovery rate orders, an increase in payroll-related costs of $5.7 million, and increased maintenance expense of $5.0 million at the thermal plants. These increases were partially offset by lower legal expenses of $2.3 million.
- Depreciation expense increased $3.9 million for the year due to increased plant in service.
- Property tax increased $4.8 million in 2011, primarily due to lower residential and commercial values in other property classes shifting tax costs to centrally assessed property.

Prior to the effects of the sharing mechanisms described above, Idaho Power operating income increased $11.5 million compared to 2010. After the effects of the sharing mechanism, operating income decreased $35.9 million compared to 2010. Also contributing to increased earnings at Idaho Power were increases of $11.6 million in AFUDC, which represents the cost of financing construction projects with borrowed funds and equity funds.

Key Operating and Financial Metrics

IDACORP’s and Idaho Power’s outlook for 2012 full year metrics is as follows:

	2012 Estimate	2011 Actual
Idaho Power Operating & Maintenance Expense (millions)	$325-$335	$339
Idaho Power Capital Expenditures, excluding AFUDC (millions)	$230-$240	$338
Idaho Power Hydroelectric Generation (million MWh)	7.5-9.5	10.9
Non-regulated subsidiary earnings and holding company expenses (millions)	$0.0-$3.0	$1.9

The 2012 range for capital expenditures includes the completion of the Langley Gulch power plant and expenditures for the siting and permitting of major transmission expansions for the Boardman-to-Hemingway and Gateway West transmission projects, net of ongoing payments from third parties participating as joint funders in the permitting project for future expenditures.

The estimated hydroelectric generation range is based on reservoir storage levels and forecasted weather conditions as of February 12, 2012.

RESULTS OF OPERATIONS

This section of the MD&A takes a closer look at the significant factors that affected IDACORP's and Idaho Power's earnings during the year ended December 31, 2011. In this analysis, the results for 2011 are compared to 2010 and the results for 2010 are compared to 2009.

(Megawatt-hours (MWh) and dollar amounts are in thousands unless otherwise indicated.)

Utility Operations

The table below presents Idaho Power's energy sales, in MWh, and supply for the last three years.

	Year Ended December 31,		
	2011	2010	2009
General business sales	13,734	13,513	13,948
Off-system sales	3,635	1,982	2,836
Total energy sales	17,369	15,495	16,784
Hydroelectric generation	10,937	7,344	8,096
Coal generation	4,820	6,864	6,941
Natural gas and other generation	138	160	242
Total system generation	15,895	14,368	15,279
Purchased power	2,751	2,401	2,912
Line losses	(1,277)	(1,274)	(1,407)
Total energy supply	17,369	15,495	16,784

For the year 2011, general business sales increased by 0.2 million MWh, mostly related to increased residential customer usage over the prior year. Off-system sales increased by 1.7 million MWh in 2011 as increases in output from hydroelectric and PURPA resources increased surplus power available for sale. Due largely to favorable hydroelectric generating conditions, hydroelectric generation comprised 69 percent of Idaho Power's total system generation during 2011. Hydroelectric generation in 2011 was 127 percent of the annual median generation of 8.6 million MWh, which is based on hydrologic conditions for the period 1928 through 2010 and adjusted to reflect the current level of water resource development. The 0.8 million MWh reduction in hydroelectric generation in 2010 compared to 2009 was primarily due to reduced precipitation during the snow accumulation period.

The increase in hydroelectric generation during 2011 led to a decreased reliance on coal-fired generation, and also contributed to the availability of additional surplus power available for off-system sales. Most of the decrease in power supply costs that typically results from increased hydroelectric generation is returned to customers through the PCA mechanisms.

Idaho Power's system is dual peaking, with the larger peak demand occurring in the summer. To reduce the magnitude of peak demands, Idaho Power has implemented a demand response program and a number of energy efficiency programs. The 2011 summer peak demand was 2,973 MW, set on July 6, 2011. The record summer peak demand of 3,214 MW was set on June 30, 2008, and the highest winter peak demand of 2,527 MW was set on December 10, 2009. During these and other similar heavy load periods, Idaho Power's system is fully committed to serve loads and meet required operating reserves. When loads exceed Idaho Power's generation capacity, Idaho Power must rely on power obtained from purchase contracts (some power from which may not be available when required if the source is intermittent power such as wind) and may be required to purchase power in the wholesale energy spot market.

***General Business Revenues*:** The table below presents Idaho Power's general business revenues, MWh sales, and number of customers for the past three years.

	Year Ended December 31,		
	2011	2010	2009
Revenue			
Residential	$ 405,982	$ 400,607	$ 409,479
Commercial	220,962	231,440	232,816
Industrial	140,701	138,394	141,530
Irrigation	104,635	110,555	109,655
Total	872,280	880,996	893,480
Provision for sharing	(27,099)	—	—
Deferred revenues [1]	(10,636)	(10,625)	(9,715)
Total general business revenues	$ 834,545	$ 870,371	$ 883,765
MWh			
Residential	5,146	4,967	5,300
Commercial	3,815	3,763	3,858
Industrial	3,100	3,076	3,140
Irrigation	1,673	1,707	1,650
Total	13,734	13,513	13,948
Customers (year end)			
Residential	411,487	408,754	406,631
Commercial	65,226	64,647	64,349
Industrial	121	125	129
Irrigation	18,736	18,547	18,818
Total	495,570	492,073	489,927

[1] As part of its February 1, 2009 general rate case order, the IPUC allowed Idaho Power to recover AFUDC for the Hells Canyon Complex relicensing asset even though the relicensing process is not yet complete and the relicensing asset has not been placed in service. Idaho Power expects to collect approximately $10.7 million annually in the Idaho jurisdiction, but will defer revenue recognition of the amounts collected until the license is issued and the asset is placed in service.

Changes in customer demand and changes in rates are the primary causes of fluctuations in general business revenue. The table below presents the most significant rate increases and decreases, shown on an annualized basis, which impacted revenues over the last three years.

Description	Effective Date	Percentage Rate Increase (Decrease)	Annualized $ Impact (millions)
2009 Idaho PCA	6/1/2009	10.2%	84
2009 Idaho AMI	6/1/2009	1.8%	11
2009 Oregon general rate case settlement	3/1/2010	15.4%	5
2010 Idaho settlement agreement	6/1/2010	9.9%	89
2010 Idaho PCA	6/1/2010	(16.4%)	(147)
2010 Idaho pension expense recovery	6/1/2010	0.8%	5
2011 Idaho PCA	6/1/2011	(4.8%)	(40)
2011 Idaho pension expense recovery	6/1/2011	1.4%	12

The Idaho general rate case settlement stipulation approved by the IPUC on December 30, 2011, resulted in a 4.2 percent overall, or $34 million annual, increase in Idaho-jurisdictional base rates, effective January 1, 2012. For more information related to the December 2011 settlement stipulation, see "Regulatory Matters" later in this MD&A.

The primary influences on customer demand are weather and economic conditions. Extreme temperatures increase sales to customers who use electricity for cooling and heating, and moderate temperatures decrease sales. Precipitation levels during the agricultural growing season affect sales to customers who use electricity to operate irrigation pumps, with increased precipitation reducing electricity usage. Boise, Idaho weather impacts for the last three years are included in the table below.

	Year Ended December 31,			
	2011	**2010**	**2009**	**Normal**
Heating degree-days [(1)]	5,554	5,078	5,612	5,727
Cooling degree-days [(1)]	1,076	914	1,188	807

[(1)] Heating and cooling degree-days are common measures used in the utility industry to analyze the demand for electricity and indicate when a customer would use electricity for heating and air conditioning. A degree-day measures how much the average daily temperature varies from 65 degrees. Each degree of temperature above 65 degrees is counted as one cooling degree-day, and each degree of temperature below 65 degrees is counted as one heating degree-day.

General Business Revenues - 2011 Compared to 2010: General business revenue decreased $35.8 million in 2011 compared to 2010. Most of the decrease is a result of recording a regulatory liability of $27.1 million to be refunded to, or otherwise be used to benefit, customers, reflecting the equal sharing of Idaho-jurisdiction earnings exceeding the authorized return on year-end equity of 10.5 percent, pursuant to a January 2010 Idaho settlement agreement. The offset to this liability was recorded as a reduction to general business revenue during the third and fourth quarters of 2011. The remaining changes in general business revenue, a decrease of $8.7 million for 2011, are primarily attributable to the effects of rate changes and usage. These factors are discussed in more detail below.

- Rates. Rate changes combined to reduce general business revenue by $38.8 million in 2011 compared to 2010. The revenue impact of several of these changes was directly offset by associated changes in operating expenses. For example, Idaho PCA amortization expense was reduced $56.3 million due to decreases in the corresponding Idaho PCA rates. The decrease in PCA rates were partially offset by an increase in base retail rates of $38.5 million for the year.

  The $10.5 million decline in revenue from commercial customers in 2011 relative to 2010, notwithstanding an increase in usage, is largely due to the disproportionate impact of the PCA rate reductions that went into effect in 2010 and 2011. Commercial customer rates are typically subject to a greater adjustment when PCA rates increase or decrease.

- Customers. Changes related to a special industrial customer contract, along with small increments in customer count, increased general business revenues by $16.6 million. Customer growth from 2010 to 2011 was 0.7 percent.

- Usage. For 2011, higher usage increased general business revenue $13.5 million compared to 2010. The increase was due primarily to colder first quarter temperatures, which increased power demand for residential heating purposes, as well as a 17.7 percent increase in cooling degree-days during the year, which increased power demand for air conditioning purposes. This increase was partially offset by a 2.3 percent decrease in irrigation usage resulting from the cooler spring weather and the timing and level of precipitation during the second quarter of 2011.

General Business Revenues - 2010 Compared to 2009:

- Rates. Rate increases positively impacted general business revenue by $16.9 million in 2010 as compared to 2009, due to increases in base rates of $73.5 million, partially offset by PCA rate decreases of $56.6 million.

- Customers. Growth in customer count contributed to a modest increase in general business revenues of $2.9 million. Customer growth from 2009 to 2010 was 0.5 percent.

- Usage. A decrease in usage reduced general business revenue by $33.4 million. Idaho Power believes the decline in total MWh sales was due primarily to mild temperatures, which decreased power demand for heating and cooling purposes, and partially due to the continued weakness of the economy and energy conservation practices in its service area.

***Off-System Sales*:** Off-system sales consist primarily of long-term sales contracts and opportunity sales of surplus system energy. The table below presents Idaho Power's off-system sales for the last three years.

	Year Ended December 31,		
	2011	**2010**	**2009**
Revenue	$ 101,602	$ 78,133	$ 94,373
MWh sold	3,635	1,982	2,836
Revenue per MWh	$ 27.95	$ 39.42	$ 33.28

Off-System Sales - 2011 Compared to 2010: Off-system sales revenue increased by $23.5 million, or 30 percent, in 2011 as compared to 2010. Sales volumes nearly doubled, as increases in output from hydroelectric and PURPA resources increased surplus power available for sale. This increase was partially offset by a 29 percent decrease in average prices due in part to abundant hydroelectric generation in the region.

Off-System Sales - 2010 Compared to 2009: Off-system sales revenue decreased $16.2 million in 2010 as compared to 2009. Hydroelectric generation decreased nine percent, which reduced surplus power available for sale. This decrease was partially offset by an 18 percent increase in revenue per MWh due to lower hydro generation in the region which drove wholesale power prices higher.

***Other Revenues*:** The table below presents the components of other revenues for the last three years.

	Year Ended December 31,		
	2011	**2010**	**2009**
Transmission services, facility rental and other	$ 48,918	$ 40,364	$ 36,037
Energy efficiency	37,663	44,184	31,821
Total	$ 86,581	$ 84,548	$ 67,858

Other Revenues - 2011 Compared to 2010: Other revenues increased $2.0 million in 2011 as compared to 2010, due mainly to:

- an increase of $7.4 million in transmission system revenues, resulting principally from increases in wheeling services attributable to increases in FERC transmission rates that took effect on October 1, 2010 and 2011, and from other facility rental increases; and
- a decrease in energy efficiency revenues of $6.5 million, due in part to an IPUC order that moved custom efficiency payments to a regulatory asset that will be amortized over time and recovered through general rate cases rather than through the energy efficiency rider. The remaining decrease relates to lower customer incentives paid versus the prior year. Energy efficiency activities are funded through a rider mechanism on customer bills. Energy efficiency program expenditures are reported as an operating expense with an equal amount of revenues recorded in other revenues, resulting in no net impact on earnings. The cumulative variance between expenditures and amounts collected through the rider is recorded as a regulatory asset or liability pending future collection from or obligation to customers. A liability balance indicates that Idaho Power has collected more than it has spent and an asset balance indicates that Idaho Power has spent more than it has collected. As of December 31, 2011, Idaho Power's energy efficiency rider balance was a regulatory asset of $8.9 million.

Other Revenues - 2010 Compared to 2009: Other revenues increased $16.7 million in 2010 as compared to 2009, due mainly to:

- an increase of $4.3 million in transmission system revenues. Transmission system revenues increased $2.8 million primarily due to new transmission facilities, as well as rate changes. Wheeling revenue increased $2.1 million primarily due to increases in the FERC formula rate that took effect on October 1, 2009 and October 1, 2010; and
- an increase in energy efficiency revenues of $12.4 million, due to increased program activity. Energy efficiency activities are funded through rider mechanisms on customer bills.

***Purchased Power*:** The table below presents Idaho Power's purchased power expenses and volumes for the last three years.

	Year Ended December 31,		
	2011	2010	2009
Expense			
PURPA contracts	$ 90,251	$ 56,022	$ 59,606
Other purchased power (including wheeling)	73,085	87,747	107,592
Total purchased power expense	$ 163,336	$ 143,769	$ 167,198
MWh purchased			
PURPA contracts	1,495	910	970
Other purchased power	1,256	1,491	1,942
Total MWh purchased	2,751	2,401	2,912
Cost per MWh from PURPA contracts	$ 60.36	$ 61.56	$ 61.45
Cost per MWh from other sources	$ 58.19	$ 58.85	$ 55.40
Weighted average - all sources	$ 59.37	$ 59.88	$ 57.42

The purchased power cost per MWh often exceeds the off-system sales revenue per MWh because Idaho Power generally needs to purchase power during heavy load periods, which is higher priced energy, than during light load periods, which is lower priced energy, and conversely has less energy available for off-system sales during heavy load periods than light load periods. Also, in accordance with Idaho Power's risk management policy, Idaho Power may purchase or sell energy several months in advance of anticipated delivery. The regional energy market price is dynamic and additional energy purchase or sale transactions that Idaho Power makes at current market prices may be noticeably different than the advance purchase or sale transactions prices.

<u>Purchased Power - 2011 Compared to 2010</u>: Purchased power expense increased $19.6 million, or 14 percent, in 2011 as compared to 2010. This increase was driven by MWh purchased from PURPA contracts, which increased 64 percent due to new PURPA wind generation facilities coming on-line. The increase was partially offset by reduced wholesale market purchases resulted from Idaho Power's above average hydroelectric generation in 2011, and continued reliance on financial hedges to mitigate potential changes in forecasted hydrologic conditions. Wholesale market purchases were also down due to lower system loads resulting from relatively mild weather.

<u>Purchased Power - 2010 Compared to 2009</u>: Purchased power expense decreased $23.4 million in 2010 as compared to 2009, due to lower system loads that resulted from mild weather, relatively weak economic conditions, energy conservation practices, and a greater reliance on financial hedges to mitigate potential changes in forecasted hydrologic conditions.

***Fuel Expense*:** Idaho Power's fuel expenses and generation at its thermal generating plants for the last three years are included in the table below.

	Year Ended December 31,		
	2011	2010	2009
Expense			
Coal	$ 119,845	$ 146,927	$ 130,234
Natural gas and other	11,697	12,746	19,332
Total fuel expense	$ 131,542	$ 159,673	$ 149,566
MWh generated			
Coal	4,820	6,864	6,941
Natural gas and other	138	160	242
Total MWh generated	4,958	7,024	7,183
Cost per MWh			
Coal	$ 24.86	$ 21.41	$ 18.76
Natural gas and other	84.76	79.66	79.88
Weighted average, all sources	26.53	22.73	20.82

Most fuel supply contracts are subject to changes in published indexes that are closely related to materials and supplies, labor, and diesel costs. In addition to commodity (variable) costs, both natural gas and coal expense include costs that are more fixed in nature for items such as capacity charges, transportation, and fuel handling. Period to period variances in fuel expense per MWh are noticeably impacted by these fixed charges when generation output is substantially different between the two periods.

Fuel Expense - 2011 Compared to 2010: In 2011, fuel expense decreased $28.1 million, or 18 percent, compared to 2010, due to lower generation at Idaho Power's thermal plants. The output at these plants was down 2.0 million MWh, or 30 percent in 2011 compared to 2010. The reduced dispatch was primarily caused by lower regional power prices due to higher regional hydroelectric and wind generation. The impact of lower thermal generation was partially offset by higher coal prices. During parts of 2010, the Bridger and Valmy generating plants received fuel from prior lower-cost contracts.

Fuel Expense - 2010 Compared to 2009: In 2010, fuel expense increased $10.1 million compared to 2009 due to new higher-priced contracts with Black Butte Coal Company for supplying the Valmy and Jim Bridger plants that took effect in early 2010. BCC, which also supplies coal to the Jim Bridger plant, experienced higher labor-related costs due to a tight labor market in the southwest Wyoming area and higher materials and supplies expense related to the underground mining operation. Fuel expense also increased due to a 31 percent increase in generation at the Boardman plant due to an extended outage in 2009 that did not recur in 2010, increasing fuel expense $1.8 million. These increases were partially offset by a $6.6 million decrease in fuel expense at the natural gas-fired peaking plants.

***PCA Mechanisms*:** Idaho Power's power supply costs can vary significantly from year to year, primarily because of the impacts of weather, system loads, and commodity markets. To address the volatility of power supply costs, Idaho Power has PCA mechanisms for both the Idaho and Oregon jurisdictions. These mechanisms allow Idaho Power to recover from or refund to customers most of the fluctuations in power supply costs. Because of these mechanisms, the primary financial impacts of power supply cost variations is that cash is paid out but recovery from customers does not occur until a future period, or cash that is collected is refunded to customers, resulting in fluctuations in operating cash flows from year to year.

PCA expense represents the effects of the Idaho and Oregon PCA mechanisms. The table below presents the components of the Idaho and Oregon PCA mechanisms for the last three years.

	Year Ended December 31,		
	2011	**2010**	**2009**
Idaho power supply cost accrual (deferral)	$ 27,768	$ (14,324)	$ (42,533)
Oregon power supply cost accrual	1,523	—	184
Oregon excess power cost order	—	—	(6,358)
Amortization of prior year authorized balances	9,206	65,550	115,417
Total power cost adjustment expense	$ 38,497	$ 51,226	$ 66,710

The power supply accruals or deferrals represent the portion of that periods' power supply cost fluctuations accrued or deferred under the PCA mechanisms.   If actual power supply costs are greater than the amount forecasted in PCA rates, most of the excess is deferred. Accruals represent additional costs recorded because actual power supply costs were less than the amount forecasted in PCA rates, as was the case for both jurisdictions in 2011. The amortization of the prior year's balances represents the amounts being collected (refunded) in the current PCA year that were deferred or accrued in the prior PCA year (the true-up component of the PCA).

PCA Mechanisms - 2011 Compared to 2010: Actual net power supply costs decreased in 2011 relative to 2010 while base net power supply costs increased, resulting in a change of $43.6 million—from a deferral of $14.3 million to an accrual of $29.3 million. For 2011, collections on deferred amounts have decreased due to lower PCA true-up rates, reducing the PCA amortization by $56.3 million.

PCA Mechanisms - 2010 Compared to 2009: A combination of changes in base power supply costs, elements of the PCA mechanism, and a decrease in PCA rates reduced PCA expenses $15.5 million in 2010 as compared to 2009. The $49.9 million decrease in the amortization of the prior year's deferral balance resulted from lower PCA true-up rates in effect in 2010. The $28.2 million decrease in the Idaho deferral is due to changes in base and actual power supply costs and forecast rates. In addition, in 2009 Idaho Power recorded the effect of an order from the OPUC that allows Idaho Power to defer for future recovery $6.4 million of costs incurred in prior years.

***Other Operations and Maintenance Expenses*:** The $44.7 million increase in other O&M expense in 2011 as compared to 2010 was principally due to:

- $20.3 million of increased pension expenses relating to the settlement stipulation that reduced a portion of Idaho customers' future obligation through a reduction in the pension regulatory asset;
- increased pension and other benefit expenses of $11.5 million, primarily due to pension expense amortization that began in June 2010 and was increased in June 2011 in conjunction with recovery of deferred pension costs in rates;
- $5.0 million in higher thermal O&M due to maintenance outages at the Valmy plant, partially offset by an equipment impairment taken in 2010 at the Bridger plant that did not recur in 2011; and
- an increase in other payroll related costs of $5.7 million.

These increases were partially offset by a combination of lower meter reading expense and the completed amortization of certain DSM expenses of $3.5 million, and lower outside service fees of $2.3 million.

Other O&M expense increased $1.3 million from 2010 to 2009, an increase of less than one percent.

Income Taxes

Income Tax Expense: IDACORP's and Idaho Power's income tax expense for 2011 decreased significantly relative to 2010, primarily as a result of an IRS examination settlement in 2011 related to Idaho Power's uniform capitalization tax accounting method. Income tax expense in 2010 was down significantly from 2009, principally as a result of Idaho Power's tax accounting method change for repair-related expenditures and lower pre-tax earnings at IDACORP and Idaho Power. For additional information relating to IDACORP's and Idaho Power's income taxes, see Note 2 - “Income Taxes” to the consolidated financial statements included in this report.

Status of Audit Proceedings and Tax Method Changes: In September 2010, Idaho Power adopted a tax accounting method change for capitalized repair expenditures on utility assets concurrent with the filing of IDACORP's 2009 consolidated federal income tax return. Also in 2010, Idaho Power reached an agreement with the IRS, subject to subsequent review by the Joint Committee, regarding the allocation of mixed service costs in its method of uniform capitalization. Both methods were subject to audit under IDACORP's 2009 IRS examination.

In April 2011, IDACORP and the IRS reached an agreement on Idaho Power's tax accounting method change for capitalized repairs. Accordingly, the IRS finalized the 2009 examination and submitted its report on the 2009 tax year to the Joint Committee for review. Idaho Power considers the capitalized repairs method effectively settled and believes that no material income tax uncertainties remain for the method. As such, Idaho Power recognized $3.4 million of its previously unrecognized tax benefits for this method in the second quarter of 2011.

In September 2011, the IRS notified IDACORP that the Joint Committee had completed its review and approved the uniform capitalization method agreement. Idaho Power considers the uniform capitalization method effectively settled and believes that no material income tax uncertainties remain for the method. Accordingly, Idaho Power recognized $56.9 million of its previously unrecognized tax benefits for tax years 2009 and prior in the third quarter of 2011.

Completion of the Joint Committee review allowed the IRS to finalize its 2009 examination, process the income tax changes, and close the case in September 2011. In the fourth quarter, IDACORP and Idaho Power paid previously accrued income tax liabilities of $3.9 million and $8.1 million, respectively, related to the capitalized repairs examination agreement. The difference in liabilities is primarily due to IDACORP's utilization of deferred federal general business tax credits. There were no 2011 cash impacts related to the uniform capitalization method settlement as income tax refunds for the method change were received in 2010. In early 2011, IDACORP requested and received the return of $13 million of previously made estimated tax payments for the 2010 tax year.

In December 2011, the IRS completed its examination of IDACORP's 2010 tax year. There were no unresolved income tax issues as a result of the IRS examination. Accordingly, the examination had no impact on IDACORP or Idaho Power's 2011 financial position, results of operations, or cash flows.

Bonus Depreciation Legislation: The Small Business Jobs Act (Jobs Act) and the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (Tax Relief Act) includes provisions for the extension and increase of bonus depreciation. Bonus depreciation provides for the accelerated deduction of current capital expenditures from certain asset classes. The Jobs Act extended 50 percent bonus depreciation to 2010 and the Tax Relief Act extended bonus depreciation to 2011-2012 and increased it to 100 percent for a portion of 2010 and 2011. Idaho Power has included an estimated bonus deprecation deduction in its current income tax provision. The estimated deduction would reduce Idaho Power's 2011 federal income tax liability by approximately $36 million. The State of Idaho did not conform to the federal bonus depreciation rules for 2010-2012.

LIQUIDITY AND CAPITAL RESOURCES

Overview

IDACORP's and Idaho Power's operating cash flows are driven principally by Idaho Power's sales of electricity and transmission capacity. General business revenues and the costs to supply power to general business customers, and the timing of income tax payments, are factors that have the greatest impact on Idaho Power's operating cash flows and are subject to risks and uncertainties relating to power generation conditions and Idaho Power's ability to obtain rate relief to cover its operating costs and provide a return on investment.

Significant uses of cash flows from Idaho Power's utility operations include the purchase of electricity, the purchase of fuel for power generation, and payment of other operating expenses, taxes, and interest, with any excess amount being available for other uses such as capital expenditures and the payment of dividends. Idaho Power is in a period of significant infrastructure investment, adding capacity to its baseload generation, transmission system, and distribution facilities in an effort to ensure an adequate supply of electricity, to provide service to new customers, and to maintain system reliability. Idaho Power's aging hydroelectric and thermal generation facilities require continuing upgrades and component replacement, and the costs related to relicensing hydroelectric facilities and complying with the new licenses are substantial. Idaho Power expects that total capital expenditures will be between $720 million and $740 million over the period from 2012 through 2014.

Idaho Power's operating cash flows usually do not fully support the amount required for utility capital expenditures during periods of significant infrastructure development. Idaho Power uses operating and capital budgets to control operating costs and optimize capital expenditures, and funds its liquidity needs for capital expenditures through cash flows from operations, debt offerings, commercial paper markets, credit facilities, and capital contributions from IDACORP. Idaho Power seeks to recover its operating costs and earn a return on its capital expenditures through rates, periodically filing for rate adjustments for recovery of operating costs and capital investments to provide the opportunity to align Idaho Power's earned returns with those allowed by regulators.

IDACORP and Idaho Power expect to continue financing capital requirements with a combination of internally generated funds and externally financed capital, and expect minimal need for external financing in 2012. However, IDACORP and Idaho Power monitor debt market conditions and may issue debt securities when they determine that, under the circumstances and in light of the timing and extent of financing needs, conditions are favorable for issuance of debt securities. Idaho Power has $100 million in principal amount of medium-term notes due in November 2012 and expects to fund retirement of those notes with cash from operations or some combination of cash from operations and the issuance of debt securities. IDACORP plans to continue to issue common stock under the pre-existing dividend reinvestment and employee-related stock purchase plans in 2012. While not expected in 2012, IDACORP may also determine to issue IDACORP common stock from time to time under its continuous equity program, depending on market conditions and capital needs. IDACORP and Idaho Power seek to maintain capital structures of approximately 50 percent debt and 50 percent equity, and maintaining this ratio influences IDACORP's and Idaho Power's debt and equity issuance decisions. As of December 31, 2011, IDACORP's capital structure consisted of approximately 52 percent equity and 48 percent debt, which decreases the likelihood that IDACORP will issue equity securities during 2012. A significant focus for 2012 will be to control costs and generate sufficient cash from operations to meet operating needs and contribute to capital expenditure requirements.

On October 26, 2011, IDACORP and Idaho Power entered into agreements that amended and restated their respective credit agreements. IDACORP's new credit facility consists of a revolving line of credit not to exceed the aggregate principal amount at any one time outstanding of $125 million, including swingline loans in an aggregate principal amount at any time outstanding not to exceed $15 million and letters of credit in an aggregate principal amount at any time outstanding not to exceed $50 million. Idaho Power's new credit facility consists of a revolving line of credit, through issuance of loans and standby letters of credit, not to exceed the aggregate principal amount at any one time outstanding of $300 million, including swingline loans in an aggregate principal amount at any time outstanding not to exceed $30 million. IDACORP and Idaho Power each have the right to request an increase in the aggregate principal amount of the new credit facilities to $150 million and $450 million, respectively, in each case subject to certain conditions.

As of February 17, 2012, IDACORP's and Idaho Power's access to debt, equity, and credit arrangements included:

- their respective $125 million and $300 million revolving credit facilities;
- IDACORP's shelf registration statement, which can be used for the issuance of debt securities and common stock, including up to 3.0 million shares of IDACORP common stock available for issuance under its continuous equity program. Approximately $539 million of debt and equity securities issuances remained available under the shelf registration statement;
- Idaho Power's shelf registration statement, which can be used for the issuance of first mortgage bonds and debt securities. $300 million remained available under the shelf registration statement; and
- IDACORP's and Idaho Power's issuance of commercial paper, which can be used to meet short-term liquidity requirements.

The conditions of the capital markets and the weak economy have in recent years caused a general concern regarding access to sufficient capital at a reasonable cost. Notwithstanding these concerns, IDACORP and Idaho Power have not been significantly affected by this disruption in the credit environment, including in the commercial paper markets, and currently expect to continue to be able to access the capital markets to meet anticipated short- and long-term borrowing needs.

Idaho Power has PCA mechanisms in place that provide for the deferral of fluctuations in purchased power and fuel costs. However, if costs rise above the level currently recovered in retail rates, deferral balances will increase, which will negatively affect cash flow and liquidity until those costs are recovered from customers.

Operating Cash Flows

IDACORP’s and Idaho Power’s operating cash inflows for the year ended December 31, 2011 were $310 million and $292 million, respectively. IDACORP's operating cash flows increased by $5 million and Idaho Power's decreased by $38 million compared to the year ended December 31, 2010. With the exception of cash flows related to income taxes, IDACORP’s operating cash flows are principally derived from the operating cash flows of Idaho Power. Significant items that affected the companies' operating cash flows in 2011 relative to 2010 included:

- income before income taxes decreased by $27 million for IDACORP and $28 million for Idaho Power;
- in 2011, Idaho Power recorded a $27 million regulatory liability in addition to a $20 million reduction to pension-related regulatory assets as a result of sharing mechanisms, which reduced income before income taxes but did not reduce operating cash flows. No sharing was recorded during 2010;
- cash outflows related to the pension and postretirement benefit plans decreased by $44 million. Idaho Power made an $18.5 million cash contribution to its defined benefit pension plan in 2011, compared with a $60 million cash contribution in 2010;
- cash inflows related to income taxes decreased by $15 million and $57 million for IDACORP and Idaho Power, respectively. IDACORP received income tax refunds of $12 million in 2011 compared with $27 million in 2010. Idaho Power’s net refunds from IDACORP for income tax were $1 million for the year, compared with $57 million for the same period in 2010;
- changes in regulatory assets associated with the Idaho and Oregon PCA mechanisms reduced cash flows by $13 million, as Idaho Power collected $56 million less of previously deferred costs due to decreases in PCA rates, partially offset by a $44 million increase in the current year PCA accrual, as compared with 2010;
- changes in fuel inventories reduced operating cash flows by $18 million, as fuel on hand increased by $20 million during 2011 due to decreased thermal plant operation, compared with $2 million during the same period in 2010; and
- differences in the timing of collections due to changes in retail accounts receivable and unbilled revenue balances decreased cash flows by $10 million, as Idaho Power collected more during 2010 than it recorded as revenues while collecting less during 2011 than it recorded as revenues.

IDACORP's and Idaho Power's operating cash inflows for the year ended December 31, 2010 were $305 million and $330 million, respectively. These amounts were an increase of $21 million and $58 million, respectively, compared to the year ended December 31, 2009. Significant items that affected operating cash flows in 2010 included:

- IDACORP's net refunds for income taxes were $27 million in 2010, as compared with $21 million in 2009. Idaho Power's net refunds from IDACORP for income tax were $57 million in 2010, as compared with $14 million in 2009;
- changes in accounts payable balances increased operating cash flows $32 million. Changes in amounts owed for

purchased power and for coal contributed $14 million and $8 million, respectively, to the change;
- differences in the timing of collections due to changes in retail accounts receivable and unbilled revenue balances increased cash flows by $32 million as Idaho Power collected less during 2009 than it recorded as revenues while collecting more during 2010 than it recorded as revenues;
- in the first quarter of 2009, $13 million of refunds were made to Idaho Power's transmission customers upon a final order from the FERC on Idaho Power's OATT; and
- Idaho Power made a $60 million contribution to its defined benefit pension plan in 2010, decreasing operating cash flows. Idaho Power did not make a contribution to its defined benefit pension plan in 2009.

Investing Cash Flows

Investing activities are predominantly related to capital expenditures for new construction and improvements to Idaho Power's generation, transmission, and distribution facilities. These capital expenditures address peak demand growth, aging plant and equipment, and customer growth. Idaho Power's construction expenditures were $338 million, $338 million, and $252 million in 2011, 2010 and 2009, respectively. In 2010, construction expenditures were partially offset by proceeds from the sale of $19 million of transmission-related assets to PacifiCorp. IDACORP cash flows relating to investments in affordable housing through IFS were $2 million, $13 million, and $6 million in 2011, 2010, and 2009, respectively.

Financing Cash Flows

Financing activities provide supplemental cash for both day-to-day operations and capital requirements as needed. Idaho Power funds liquidity needs for capital investment, working capital, energy and price hedging, and other financial commitments through cash flows from continuing operations, public debt offerings, commercial paper markets, credit facilities, and contributions from IDACORP. IDACORP funds its cash requirements, such as payment of taxes, capital contributions to Idaho Power, and non-utility expenses allocated to IDACORP, through cash flows from operations, commercial paper markets, sales of common stock, and credit facilities.

***Debt*:** On March 2, 2011, Idaho Power repaid at maturity $120 million of its 6.60% first mortgage bonds (secured notes) using a portion of the proceeds from the first mortgage bonds issued in August 2010 discussed in the next paragraph. Idaho Power's next upcoming material long-term debt principal repayment obligation is its $100 million of 4.75% first mortgage bonds that mature in November 2012.

On August 30, 2010, Idaho Power issued $100 million of 3.40% first mortgage bonds, Series I due 2020 and $100 million of 4.85% first mortgage bonds, Series I due 2040 under a shelf registration statement.

On December 1, 2009, Idaho Power repaid at maturity $80 million of its 7.2% first mortgage bonds. On November 20, 2009, Idaho Power issued $130 million of its 4.5% first mortgage bonds, Series H, due March 1, 2020. On August 20, 2009, Idaho Power completed the remarketing of its $166.1 million pollution control revenue refunding bonds and on August 25, 2009, Idaho Power used the proceeds from the remarketed bonds plus other funds to prepay its $170 million term loan credit agreement. On March 30, 2009, Idaho Power issued $100 million of its 6.15% first mortgage bonds, Series H due April 1, 2019. During 2009, IDACORP and Idaho Power reduced short-term debt by $94 million and $109 million, respectively.

***Equity*:** IDACORP has entered into sales agency agreements as a means of selling its common stock from time to time in at-the-market offerings. IDACORP did not issue any shares under these agreements in 2011. In 2010, IDACORP received $34 million, net of agent's fees, from the issuance of 973,585 shares of IDACORP common stock at an average price of $35.47. In 2009, IDACORP received $14 million, net of agent's fees, from the issuance of 489,360 shares of IDACORP common stock at an average price of $28.79. IDACORP entered into a new sales agency agreement with BNY Mellon Capital Markets, LLC on December 16, 2011, replacing a December 2008 sales agency agreement that provided for the sale of up to 3 million shares of IDACORP common stock. At the time of expiration of the December 2008 sales agency agreement, 1,165,233 shares were unissued. As of February 17, 2012, there were 3 million shares available for issuance under the current sales agency agreement.

IDACORP issues common stock under its Dividend Reinvestment and Stock Purchase Plan and the Idaho Power Company Employee Savings Plan (a 401(k) plan), which provides additional common equity to IDACORP's capital structure. Under these plans, IDACORP issued 211,276 shares in 2011, 250,030 shares in 2010, and 366,673 shares in 2009, for proceeds of $8.2 million, $8.6 million, and $9.6 million, respectively.

IDACORP issued 255,746 shares of IDACORP common stock in 2011, 194,860 shares in 2010, and 25,800 shares in 2009, in connection with the exercise of stock options, for proceeds of $9.4 million, $5.4 million, and $0.6 million, respectively.

IDACORP and Idaho Power paid dividends of $60 million, $58 million, and $57 million in 2011, 2010, and 2009, respectively. IDACORP made capital contributions of $16 million, $50 million, and $20 million to Idaho Power in 2011, 2010, and 2009, respectively.

Financing Programs

Shelf Registrations: IDACORP has an effective shelf registration statement on file with the U.S. Securities and Exchange Commission (SEC) that, as of the date of this report, can be used for the issuance of up to $539 million of debt securities and common stock. Idaho Power has an effective shelf registration statement on file with the SEC that, as of the date of this report, can be used for the issuance of up to $300 million of first mortgage bonds and unsecured debt. Refer to Note 4 - "Long-Term Debt" to the consolidated financial statements included in this report for more information regarding long-term financing arrangements.

The issuance of first mortgage bonds requires that Idaho Power meet interest coverage and security provisions set forth in the Indenture of Mortgage and Deed of Trust securing the bonds. Future issuances of first mortgage bonds are subject to satisfaction of covenants and security provisions set forth in the Indenture of Mortgage and Deed of Trust, market conditions, and regulatory authorizations, and satisfaction of covenants and tests contained in other financing agreements. The Indenture of Mortgage and Deed of Trust limits the amount of additional first mortgage bonds that Idaho Power may issue to the sum of (a) the principal amount of retired first mortgage bonds and (b) 60 percent of total unfunded property additions, as defined in the Indenture of Mortgage and Deed of Trust. As of December 31, 2011, Idaho Power could issue approximately $1.3 billion of additional first mortgage bonds based on retired first mortgage bonds and total unfunded property additions. However, the Indenture of Mortgage and Deed of Trust further limits the maximum amount of first mortgage bonds at any one time outstanding to $2.0 billion, and as a result the maximum amount of first mortgage bonds Idaho Power could issue as of December 31, 2011 was limited to approximately $539 million. Idaho Power may increase the $2.0 billion limit on the maximum amount of first mortgage bonds outstanding by filing a supplemental indenture with the trustee as provided in the Indenture of Mortgage and Deed of Trust.

Credit Facilities**:** As described above, on October 26, 2011, IDACORP and Idaho Power executed new credit agreements that amended and restated their existing $100 million and $300 million credit facilities, respectively. Each of the new credit facilities mature on October 26, 2016, and may be used for general corporate purposes and commercial paper back-up. IDACORP's facility permits borrowings under a revolving line of credit of up to $125 million at any one time outstanding, including swingline loans not to exceed $15 million at any time and letters of credit not to exceed $50 million at any time. IDACORP's facility may be increased, subject to specified conditions, to $150 million. Idaho Power's facility permits borrowings through the issuance of loans and standby letters of credit of up to $300 million at any one time outstanding, including swingline loans not to exceed $30 million at any one time. Idaho Power's facility may be increased, subject to specified conditions, to $450 million. Each company may request up to two one-year extensions of the then-existing maturity date. The interest rates for any borrowings under the facilities are based on either (1) a floating rate that is equal to the highest of the prime rate, federal funds rate plus 0.5 percent, or LIBOR rate plus 1.0 percent, or (2) the LIBOR rate, plus, in each case, an applicable margin. The applicable margin is based on IDACORP's or Idaho Power's, as applicable, senior unsecured long-term indebtedness credit rating by Moody's Investors Service, Inc., Standard and Poor's Ratings Services, and Fitch Rating Services, Inc., as set forth on a schedule to the credit agreements. The companies also pay a facility fee based on the respective company's credit rating for senior unsecured long-term debt securities.

Each facility contains a covenant requiring each company to maintain a leverage ratio of consolidated indebtedness to consolidated total capitalization equal to or less than 0.65 as of the end of each fiscal quarter. In determining the leverage ratio, "consolidated indebtedness" broadly includes all indebtedness of the respective borrower and its subsidiaries, including, in some instances, indebtedness evidenced by certain hybrid securities (as defined in the credit agreement). "Consolidated total capitalization" is calculated as the sum of all consolidated indebtedness, consolidated stockholders' equity of the borrower and its subsidiaries, and the aggregate value of outstanding hybrid securities. At December 31, 2011, the leverage ratios for IDACORP and Idaho Power were 48 percent and 49 percent, respectively. IDACORP's and Idaho Power's ability to utilize the credit facilities is conditioned upon their continued compliance with the leverage ratio covenants included in the credit facilities, which could limit the ability of the companies to issue first mortgage bonds and debt securities. There are additional covenants, subject to exceptions, that prohibit certain mergers, acquisitions, and investments, restrict the creation of certain liens, and prohibit entering into any agreements restricting dividend payments from any material subsidiary. At February 17, 2012, IDACORP and Idaho Power were in compliance with all facility covenants.

The events of default under both facilities include, without limitation, non-payment of principal, interest, or fees; materially false representations or warranties; breach of covenants; bankruptcy or insolvency events; condemnation of property; cross-default to certain other indebtedness; failure to pay certain judgments; change of control; failure of IDACORP to own free and clear of liens the voting stock of Idaho Power; the occurrence of specified events or the incurring of specified liabilities relating to benefit plans; and the incurrence of certain environmental liabilities, subject, in certain instances, to cure periods.

Upon any event of default relating to the voluntary or involuntary bankruptcy of IDACORP or Idaho Power or the appointment of a receiver, the obligations of the lenders to make loans under the applicable facility and to issue letters of credit will automatically terminate and all unpaid obligations will become due and payable. Upon any other event of default, the lenders holding greater than 50 percent of the outstanding loans or greater than 50 percent of the aggregate commitments (required lenders) or the administrative agent with the consent of the required lenders may terminate or suspend the obligations of the lenders to make loans under the facility and to issue letters of credit under the facility and/or declare the obligations to be due and payable. During an event of default under the facilities, the lenders may, at their option, increase the applicable interest rates then in effect and the letter of credit fee by 2.0 percent per annum. A ratings downgrade would result in an increase in the cost of borrowing, but would not result in a default or acceleration of the debt under the facilities. However, if Idaho Power's ratings are downgraded below investment grade, Idaho Power must extend or renew its authority for borrowings under its IPUC and OPUC regulatory orders.

Without additional approval from the IPUC, the OPUC, and the Public Service Commission of Wyoming, the aggregate amount of short-term borrowings by Idaho Power at any one time outstanding may not exceed $450 million.

The following table outlines available short-term borrowing liquidity as of the dates specified:

	December 31, 2011		**December 31, 2010**	
	IDACORP[(2)]	**Idaho Power**	**IDACORP[(2)]**	**Idaho Power**
Revolving credit facility	$ 125,000	$ 300,000	$ 100,000	$ 300,000
Commercial paper outstanding	(54,200)	—	(66,900)	—
Identified for other use[(1)]	—	(24,245)	—	(24,245)
Net balance available	$ 70,800	$ 275,755	$ 33,100	$ 275,755

(1) Port of Morrow and American Falls bonds that holders may put to Idaho Power

(2) These amounts represent the IDACORP facility only.

At February 17, 2012, IDACORP had no amounts outstanding under its credit facility and $51.5 million of commercial paper outstanding, and Idaho Power had no amounts outstanding under its credit facility and no commercial paper outstanding.

The following table presents additional information about short-term borrowing during the years ended December 31, 2011 and 2010:

	December 31, 2011		**December 31, 2010**	
	IDACORP [(1)]	**Idaho Power**	**IDACORP[(1)]**	**Idaho Power**
Commercial paper:				
Year end:				
Amount outstanding	$ 54,200	$ —	$ 66,900	$ —
Weighted average interest rate	0.47%	—%	0.43%	—%
Daily average amount outstanding during the year	$ 65,574	$ —	$ 19,754	$ 348
Weighted average interest rate during the year	0.41%	—%	0.40%	0.43%
Maximum month-end balance	$ 74,400	$ —	$ 66,900	$ 5,500

(1) These amounts represent IDACORP only.

Impact of Credit Ratings on Liquidity

IDACORP's and Idaho Power's access to capital markets, including the commercial paper market, and their respective financing costs in those markets, may depend on their respective credit ratings. The following table outlines the ratings of Idaho Power's and IDACORP's securities, and the ratings outlook, by Standard & Poor's Ratings Services and Moody's Investors Service as of the date of this report:

	S&P		**Moody's**	
	Idaho Power	**IDACORP**	**Idaho Power**	**IDACORP**
Corporate Credit Rating/Long-Term Issuer Rating	BBB	BBB	Baa 1	Baa 2
Senior Secured Debt	A-	None	A2	None
Senior Unsecured Debt	BBB	None	Baa 1	None
Short-Term Tax-Exempt Debt	BBB/A-2	None	Baa 1/ VMIG-2	None
Commercial Paper	A-2	A-2	P-2	P-2
Senior Unsecured Credit Facility	None	None	Baa 1	Baa 2
Rating Outlook	Stable	Stable	Stable	Stable

These security ratings reflect the views of the ratings agencies. An explanation of the significance of these ratings may be obtained from each rating agency. Such ratings are not a recommendation to buy, sell, or hold securities. Any rating can be revised upward or downward or withdrawn at any time by a rating agency if it decides that the circumstances warrant the change. Each rating agency has its own methodology for assigning ratings and, accordingly, each rating should be evaluated independently of any other rating.

Idaho Power maintains margin agreements relating to its wholesale commodity contracts that allow performance assurance collateral to be requested of and/or posted with certain counterparties. As of December 31, 2011, Idaho Power had posted no performance assurance collateral. Should Idaho Power experience a reduction in its credit rating on Idaho Power's unsecured debt to below investment grade Idaho Power could be subject to additional requests by its wholesale counterparties to post performance assurance collateral. Counterparties to derivative instruments and other forward contracts could request immediate payment or demand immediate ongoing full daily collateralization on derivative instruments and contracts in net liability positions. Based upon Idaho Power's current energy and fuel portfolio and market conditions as of December 31, 2011, the approximate amount of collateral that could be requested upon a downgrade to below investment grade is approximately $7 million. Idaho Power actively monitors the portfolio exposure and the potential exposure to additional requests for performance assurance collateral calls, through sensitivity analysis, to minimize capital requirements.

Capital Requirements

Idaho Power's construction expenditures were $338 million during the year ended December 31, 2011. The following table presents Idaho Power's estimated cash requirements for construction, excluding AFUDC, for 2012 through 2014 (in millions of dollars):

	2012	**2013-2014**
Ongoing capital expenditures	$200-205	$490-500
Langley Gulch Power Plant (detailed below)	30-35	-
Total	$230-240	$490-500

Major Infrastructure Projects: Idaho Power is undertaking a number of significant infrastructure projects, described below.

Langley Gulch Power Plant: The Langley Gulch Power Plant is a natural gas-fired combined cycle combustion turbine generating plant with a summer nameplate capacity of approximately 300 MW and a winter capacity of approximately 330 MW. Construction of the plant, substation, and transmission lines is in process. The plant is being constructed near New Plymouth, Idaho and is contracted to achieve commercial operation by November 1, 2012. Based on the current project status, Idaho Power estimates that the plant will be in service by July 1, 2012. The commitment estimate for the project is $427.4 million, $355 million of which Idaho Power incurred from inception in 2009 through December 31, 2011. AFUDC is included in both amounts. As of the date of this report, the overall project remains on schedule and Idaho Power expects the total project cost to be below the commitment estimate. Throughout 2011, significant progress was made constructing the plant and most equipment, facilities, and systems are complete. The construction contractor is preparing for commissioning of the plant, with testing planned to start in the first quarter of 2012. The step-up transformers were commissioned and energized from the substation in the fourth quarter of 2011. The plant will be connected to Idaho Power's existing grid through a new substation and two new transmission lines. The substation and one of the transmission lines have been completed. The second transmission line is under construction and is expected to be completed by May 2012.

Transmission Projects: As described in its 2011 Integrated Resource Plan (IRP), Idaho Power continues to focus on expansion of its existing transmission system in an effort to improve system reliability and resource adequacy. Idaho Power is involved in two significant transmission projects -- the Boardman-to-Hemingway line, a proposed 300-mile, 500-kV transmission project between a station near Boardman, Oregon and the Hemingway station near Boise, Idaho, and the Gateway West project, a joint development with PacifiCorp to build transmission lines between a station located near Douglas, Wyoming and the Hemingway station.

Boardman to Hemingway Line. The Boardman-to-Hemingway line will provide transmission service to meet needs identified in the 2011 IRP and other requests pursuant to Idaho Power's OATT. The Oregon Department of Energy's Energy Facility Siting Council (EFSC) process and the National Environmental Policy Act (NEPA) process are under way. Idaho Power is working with the EFSC to develop a phased approach to the EFSC's process so it can run concurrently with the NEPA process. Idaho Power expects to receive the EFSC project order in the first quarter of 2012. Idaho Power is preparing the preliminary application for site certificate pursuant to that process and anticipates filing the application in December 2012. The U.S. Bureau of Land Management (BLM) is in the process of publishing the draft environmental impact statement (DEIS) that Idaho Power expects will include both Idaho Power's proposed route and other alternative routes. Idaho Power anticipates the DEIS will be published in February 2013. In January 2012, Idaho Power entered into a joint funding agreement with PacifiCorp and BPA, described below, to jointly pursue the permitting of the project. Idaho Power's estimated share of the cost of the permitting phase of the project, after reflecting the terms of the joint funding agreement, is $11 million, including AFUDC. Total cost estimates for the project are approximately $820 million, including AFUDC. This cost estimate excludes the impacts of inflation and price changes of materials and labor resources that may occur following the date of the estimate. Idaho Power's share of the permitting phase of the project (excluding AFUDC) is included in the capital requirements table above. Construction costs beyond the initial phase are not included in the table above. The preferred portfolio in the 2011 IRP provides for a 2016 in-service date for the transmission line, as immediate system reliability benefits could be realized by construction of the transmission line by that date. However, the actual completion date of the project is subject to siting, permitting, regulatory approvals, individual participant's in-service requirements, the terms of any resulting joint construction agreements, and other conditions. Idaho Power will continue to work with the BLM, Oregon Department of Fish and Wildlife, and other agencies to address environmental issues, which could delay the project, alter the proposed siting, and result in significantly higher costs.

Gateway West Line. Idaho Power and PacifiCorp are pursuing the joint development of the Gateway West project. In January 2012, Idaho Power and PacifiCorp entered a new joint funding agreement for permitting the project as described below. Idaho Power's estimated cost for the permitting phase of the Gateway West project is approximately $24 million, including AFUDC. As of the date of this report, Idaho Power estimates the total cost for its share of the project (including both permitting and construction) to be between $150 million and $300 million, including AFUDC. Idaho Power's share of the permitting phase of the project (excluding AFUDC) is included in the capital requirements table above. Construction costs are not included in the table above. Timing of the construction of each segment of the project is subject to siting, permitting, regulatory approvals, individual participant's in-service requirements, the terms of any resulting joint construction agreements, and other conditions.

On July 29, 2011, the BLM issued for public review and comment a DEIS for the Gateway West project. The DEIS did not identify a preferred route for the project. Idaho Power provided input for comments relating to the DEIS that PacifiCorp submitted to the BLM in October 2011. As of the date of this report, the BLM continues to work through its NEPA process to address the lack of an agency preferred route and to address sage grouse and other resource issues.

Rapid Response Team for Transmission. The Obama Administration announced on October 5, 2011 the Rapid Response Team for Transmission (RRTT) pilot program to streamline federal permitting and increase cooperation at the federal, state, and tribal levels for several transmission projects. The Boardman-to-Hemingway and Gateway West projects are included in the RRTT pilot projects. Idaho Power is participating in the RRTT process for both the Boardman-to-Hemingway and Gateway West projects, but is unable to predict whether the RRTT will have a positive impact on the timing or ultimate cost of either project.

Agreements Relating to Transmission Projects*:*

March 2010 Memorandum of Understanding. In March 2010, Idaho Power and PacifiCorp entered into a Memorandum of Understanding (2010 MOU) under which Idaho Power and PacifiCorp agreed to negotiate in good faith to reach arrangements pertaining to, among other items, the sale by the parties to one another of an undivided ownership interest in certain transmission facilities, and joint development and construction of three transmission projects, including the Boardman-to-Hemingway and Gateway West projects. In April 2010, Idaho Power and PacifiCorp entered into an arrangement pursuant to which they agreed to sell to one another interests in certain high-voltage transmission-related and interconnection equipment, and in May 2010 executed agreements pertaining to the joint ownership and operation of portions of those facilities. In subsequent months, Idaho Power and PacifiCorp sought to negotiate the terms and conditions of the other arrangements contemplated by the 2010 MOU, including the Boardman-to-Hemingway and Gateway West transmission projects, but were unable to reach agreement on those arrangements, and the 2010 MOU was ultimately terminated in April 2011. However, on January 12, 2012, Idaho Power, PacifiCorp, and the Bonneville Power Administration (BPA) entered into arrangements pertaining to the Boardman-to-Hemingway project and meeting BPA's eastern Idaho load service obligations, described below. Idaho Power and PacifiCorp also entered into an arrangement pertaining to the Gateway West project, as described below.

Boardman to Hemingway Transmission Project Joint Permit Funding Agreement, dated January 12, 2012, among Idaho Power, PacifiCorp, and the Bonneville Power Administration (B2H Funding Agreement). The B2H Funding Agreement provides that the parties will seek to jointly fund and support the process of completing environmental studies, including an environmental impact statement pursuant to the National Environmental Policy Act, and obtaining governmental authorizations and permits for rights-of-way over public lands, necessary to develop the project. The planning, design, procurement, and acquisition of private rights-of-way, private easements, and similar private property interests are not within the scope of the B2H Funding Agreement. Idaho Power is designated as the project manager under the B2H Funding Agreement, responsible for administering and overseeing the project and for the day-to-day activities involved in advancing the project. The B2H Funding Agreement assigns each party a permitting interest based on each party's specified capacity ownership interests. The agreement provides for permitting interests of 21.21 percent for Idaho Power, 24.24 percent for BPA, and 54.55 for PacifiCorp in the Boardman-to-Hemingway transmission project. The agreement further provides that during future negotiations pertaining to development and construction agreements, the parties will seek to retain interests in the project equal to their respective permitting interests. PacifiCorp or BPA may withdraw from the B2H Funding Agreement at any time. Idaho Power has no right to withdraw from the B2H Funding Agreement.

Gateway West Transmission Project Development Agreement, dated January 12, 2012, between Idaho Power and PacifiCorp (Gateway Funding Agreement). The Gateway Funding Agreement outlines the terms under which the parties will jointly own, develop, design, permit, site, and acquire rights-of-way for the Gateway West transmission project. Idaho Power's interest in the Gateway West project applies to four of ten segments involved in the project, referred to as segments 6 (which Idaho Power had previously constructed and is included only for purposes of federal permitting related to the Gateway West project), 8, 9, and 10. PacifiCorp is designated as the project manager under the agreement. The Gateway Funding Agreement provides that the project manager may seek to reconfigure portions of the federal permitting project, including segments in which Idaho Power has an interest, subject to certain limitations. Further, PacifiCorp retains the right to remove specified segments from the federal permitting project, including segments in which Idaho Power has an interest, subject to certain limitations and Idaho Power's ability to continue with the permitting and construction of certain removed segments.

Each party is responsible for its pro rata share, based on its respective federal and state permitting ownership interest, of the costs incurred under the agreement. Idaho Power's state permitting interest in its segments is 100 percent for segment 6 and 33 percent for each of segments 8, 9, and 10, with a federal permitting interest in the project of 11 percent. PacifiCorp has a 100 percent state permitting interest in segments 1, 2, 3, 4, 5, and 7, and a 67 percent state permitting interest in segments 8, 9, and 10, and has a federal permitting interest of 89 percent in the project. Information on the segments in which Idaho Power has an interest is as follows:

Segment No.	**Connected Substations**	**Length of Line (Miles)**	**Size of Line**	**State**
6	Borah to Midpoint	88	500-kV	Idaho
8	Midpoint to Hemingway	126	500-kV	Idaho
9	Cedar Hill to Hemingway	152	500-kV	Idaho
10	Midpoint to Cedar Hill	34	500-kV	Idaho

The Gateway Funding Agreement provides for the parties to subsequently meet to negotiate the terms and conditions of one or more definitive development and construction agreements for the Gateway West transmission line. The agreement specifies that the parties intend that the terms of any construction agreement would provide that Idaho Power is entitled to one-third of the anticipated bi-directional transmission capacity on segments 8, 9, and 10, and one-third of any total incremental system capacity on those segments, and that PacifiCorp is entitled to the remaining two-thirds interest. A party may withdraw from the federal permitting project, all or a portion of the state permitting project (relating to one or two of segments 8, 9, and 10), or the agreement in its entirety. Upon withdrawal, the withdrawing party forfeits its rights, title, and interest in the agreement and associated tangible and intangible property rights or, if withdrawing from less than all segments, its rights, title, and interest in those segments.

Idaho Power was previously a party to an existing memorandum of understanding, dated May 7, 2007, relating to transmission project development, and a permitting cost sharing agreement, dated September 5, 2008, to share with PacifiCorp the costs of certain Gateway West project permitting activities. The prior memorandum of understanding and permitting agreement terminated upon execution of the Gateway Funding Agreement.

Memorandum of Understanding, dated January 12, 2012, among Idaho Power, PacifiCorp, and BPA (2012 MOU). The 2012 MOU provides that the parties will negotiate in good faith the terms of mutually satisfactory definitive agreements that would allow BPA to meet its load service obligations in southeast Idaho. It provides that the parties will explore opportunities to establish eastern Idaho load service from the Hemingway substation in exchange for similar service from the Federal Columbia River Transmission System, and will consider whether to replace certain transmission arrangements involving existing assets with joint ownership transmission or other arrangements. The 2012 MOU outlines at least two potential alternatives for further negotiation, including a network service option and an asset ownership rights option on certain of Idaho Power's and PacifiCorp's transmission systems. Any party may terminate the 2012 MOU at any time, without penalty, and the 2012 MOU automatically expires on December 31, 2014.

AMI/Smart Grid and American Recovery and Reinvestment Act of 2009 (ARRA): The advanced metering infrastructure (AMI) project provides the means to automatically retrieve energy consumption information, eliminating manual meter reading expense. In December 2011, Idaho Power completed the installation of this technology for approximately 99 percent of its customers, installing approximately 488,000 AMI meters at a cost of $71.8 million.

Under the ARRA, Idaho Power was awarded a grant of $47 million from the U.S. Department of Energy (DOE). This grant matches a $47 million investment by Idaho Power in Smart Grid technology, including AMI. The grant was signed by the DOE on April 2, 2010 and applies to project costs incurred beginning in August 2009 for a three-year term. As of December 31, 2011, Idaho Power had invoiced approximately $33.2 million from the DOE, of which $32.8 million had been received, and expects to continue billing and collecting monthly over the remaining term of the award. The costs to be reimbursed by the grant are not included in the Capital Requirements table above.

Environmental Regulation Costs: As of the date of this report, Idaho Power estimates incurring approximately $60 million in capital and operating costs for environmental facilities during 2012. Hydroelectric facility expenses, including costs for relicensing the HCC, and thermal plant expenses account for approximately $33 million and $27 million, respectively. From 2013 through 2014, total environmental-related operating and capital costs are estimated to be approximately $205 million. Expenses related to the hydroelectric facilities during that period are expected to be $79 million and include costs associated with the relicensing of the HCC. Thermal plant expenses are expected to total $126 million during this period. The capital portion of these amounts are included in the Capital Requirements table above but do not include costs related to possible changes in current or new environmental laws or regulations and enforcement policies that may be enacted in response to issues such as climate change and emissions from coal-fired and gas-fired generation plants.

***Other Capital Requirements*:** IDACORP's non-regulated capital expenditures have primarily related to IFS's tax-structured investments. As of the date of this report, IDACORP does not anticipate any significant expenditures for 2012 through 2014.

Retirement Benefit Plans

Idaho Power made a $60 million contribution in 2010 and an $18.5 million contribution in 2011 to its defined benefit pension plan. In 2012 and beyond, Idaho Power expects significant contribution obligations under its retirement benefit plans. Refer to Note 11 - "Benefit Plans" to the consolidated financial statements included in this report and to the section titled "Contractual Obligations" below in this MD&A for information relating to those obligations.

Contractual Obligations

The following table presents IDACORP's and Idaho Power's contractual cash obligations for the respective periods in which they are due:

	Payment Due by Period				
	Total	2012	2013-2014	2015-2016	Thereafter
Idaho Power:	(millions of dollars)				
Long-term debt[(1)]	$ 1,492	$ 101	$ 72	$ 2	$ 1,317
Future interest payments[(2)]	1,268	79	145	141	903
Operating leases	27	2	6	3	16
Purchase obligations:					
Cogeneration and small power production	4,673	147	405	433	3,688
Large power production[(3)]	19	19	—	—	—
Fuel supply agreements	340	79	131	32	98
Purchased power & transmission[(4)]	27	11	8	4	4
Other[(5)]	160	51	43	25	41
Pension and postretirement benefit plans[(6)]	286	41	103	100	42
Other long-term liabilities - Idaho Power	1	—	—	—	1
Total Idaho Power	8,293	530	913	740	6,110
Other	1	—	1	—	—
Total IDACORP	$ 8,294	$ 530	$ 914	$ 740	$ 6,110

(1) For additional information, see Note 4 – "Long-Term Debt" to the consolidated financial statements included in this report.

(2) Future interest payments are calculated based on the assumption that all debt is outstanding until maturity. For debt instruments with variable rates, interest is calculated for all future periods using the rates in effect at December 31, 2011.

(3) Large power production relates to the Langley Gulch power plant and includes two contracts with Siemens Energy, Inc. relating to the purchase of a gas turbine and the purchase of a steam turbine, and an Engineering, Procurement and Construction Services Agreement with Boise Power Partners Joint Venture, a joint venture consisting of Kiewit Power Engineers Co. and TIC-The Industrial Company, for design, engineering, procurement, construction management, and construction services for Langley Gulch.

(4) Approximately $9 million of the obligations included in purchased power and transmission have contracts that do not specify terms related to expiration. As these contracts are presumed to continue indefinitely, 10 years of information estimated based on current contract terms has been included in the table for presentation purposes.

(5) Approximately $81 million of the amounts in other purchase obligations are contracts that do not specify terms related to expiration. As these contracts are presumed to continue indefinitely, 10 years of information, estimated based on current contract terms, has been included in the table for presentation purposes.

(6) Idaho Power estimates pension contributions based on actuarial data. As of the date of this report, Idaho Power cannot estimate pension contributions beyond 2016 with any level of precision, and amounts through 2016 are estimates only. For more information on pension and postretirement plans, refer to Note 11 – "Benefit Plans" to the consolidated financial statements included in this report.

Dividends

The amount and timing of dividends paid on IDACORP's common stock are within the discretion of IDACORP's board of directors. IDACORP's board of directors reviews the dividend rate periodically to determine its appropriateness in light of IDACORP's current and long-term financial position and results of operations, capital requirements, rating agency requirements, contractual and regulatory restrictions, legislative and regulatory developments affecting the electric utility industry in general and Idaho Power in particular, competitive conditions, and any other factors the board of directors deems relevant. The ability of IDACORP to pay dividends on its common stock is dependent upon dividends paid to it by its subsidiaries, primarily Idaho Power. At its November 2011 meeting, the IDACORP board of directors adopted a dividend policy for IDACORP that provides for a target long-term dividend payout ratio of between 50 and 60 percent of sustainable IDACORP earnings, with the flexibility to achieve that payout ratio over time and to adjust the payout ratio or to deviate from the target payout ratio from time to time based on the various factors that drive the board's dividend decisions. Notwithstanding the dividend policy adopted by the IDACORP board, the dividends IDACORP pays remain in the discretion of the board of directors who, when evaluating the dividend amount, will continue to take into account the foregoing factors, among others. On January 19, 2012, IDACORP's board of directors voted to increase the quarterly dividend payable February 29, 2012 to $0.33 per share of IDACORP common stock, from the prior quarterly dividend amount of $0.30 per share of IDACORP common stock. For additional information relating to IDACORP and Idaho Power dividends, including restrictions on IDACORP's and Idaho Power's payment of dividends, see Note 6 – "Common Stock" to the consolidated financial statements included in this report.

Contingencies and Proceedings

IDACORP and Idaho Power are involved in a number of litigation, alternative dispute resolution, and administrative proceedings, and are subject to claims and legal actions arising in the ordinary course of business, that could affect their future earnings and financial condition. Certain legal proceedings to which IDACORP or Idaho Power are parties or are otherwise involved are described in Note 10 - "Contingencies" to the consolidated financial statements included in this report. Except where noted in Note 10, IDACORP and Idaho Power are unable to predict the outcomes of the matters or estimate the impact the proceedings may have on their financial positions, results of operations, or cash flows.

Off-Balance Sheet Arrangements

Idaho Power has agreed to guarantee a portion of the performance of reclamation activities and obligations at BCC, of which IERCo owns a one-third interest. This guarantee, which is renewed each December, was $63 million at December 31, 2011, representing IERCo's one-third share of BCC's total reclamation obligation of $189 million. BCC has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. At December 31, 2011, the value of the reclamation trust fund totaled $80 million. BCC periodically assesses the adequacy of the reclamation trust fund and its estimate of future reclamation costs. To ensure that the reclamation trust fund maintains adequate reserves, BCC has the ability to add a per-ton surcharge to coal sales. Starting in 2010, BCC began applying a nominal surcharge to coal sales in order to maintain adequate reserves in the reclamation trust fund. Because of the existence of the fund and the ability to apply a per-ton surcharge, the estimated fair value of this guarantee is minimal.

REGULATORY MATTERS

Overview

Idaho Power continues to focus on timely recovery of its costs through filings with the IPUC, OPUC, and the FERC. The discussion below highlights certain notable regulatory determinations and pending matters or issues that may have a material impact on IDACORP's and Idaho Power's business or results. Regulatory matters, and in many cases their financial impact on IDACORP and Idaho Power, are also discussed in Note 3 - “Regulatory Matters” to the consolidated financial statements included in this report, which should be read in conjunction with the discussion below.

Idaho and Oregon Significant Rate Changes

As a regulated utility, the prices that the IPUC and OPUC authorize Idaho Power to charge for its retail services is a major factor in determining IDACORP’s and Idaho Power’s results of operations and financial condition. The table below summarizes notable rate increases and decreases, shown on an annualized basis, in recent years. Certain of the regulatory actions that resulted in the rate increases and decreases are described in more detail in this section of MD&A or in Note 3 - “Regulatory Matters” to the consolidated financial statements included in this report.

Description	Effective Date	Percentage Rate Increase (Decrease)	Estimated Annualized $ Impact (millions)
2008 Idaho general rate case	2/1/2009	3.1 %	$ 21
2008 Idaho general rate case	3/19/2009	0.9 %	6
2009 Idaho PCA	6/1/2009	10.2 %	84
2009 Idaho AMI	6/1/2009	1.8 %	11
2009 Oregon APCU	6/1/2009	11.5 %	4
2009 Oregon general rate case settlement	3/1/2010	15.4 %	5
2010 Idaho settlement	6/1/2010	9.9 %	89
2010 Idaho PCA	6/1/2010	(16.4)%	(147)
2010 Idaho pension expense recovery	6/1/2010	0.8 %	5
2011 Idaho PCA	6/1/2011	(4.8)%	(40)
2011 Idaho pension expense recovery	6/1/2011	1.4 %	12
2011 Idaho general rate case settlement	1/1/2012	4.1 %	34

Change in Deferred (Accrued) Net Power Supply Costs

Deferred power supply costs represent certain differences between Idaho Power's actual net power supply costs and the costs included in its retail rates, the latter being based on annual estimates of power supply costs. Deferred power supply costs are recorded on the balance sheets for future recovery or refund through customer rates. The table below summarizes the change in deferred net power supply costs over the last two years.

	Idaho	Oregon[(1)]	Total
Balance at December 31, 2009	$ 71,412	$ 13,221	$ 84,633
Costs deferred through PCA and PCAM	14,324	—	14,324
Prior costs expensed and recovered through rates	(63,757)	(1,792)	(65,549)
SO_2 allowances credited to account	(4,504)	79	(4,425)
Interest and other	84	686	770
Balance at December 31, 2010	17,559	12,194	29,753
Current period net power supply costs accrued	(27,768)	(1,523)	(29,291)
Prior costs expensed and recovered through rates	(6,849)	(2,357)	(9,206)
Transfer of energy efficiency expenditures	10,000	—	10,000
SO_2 allowance and renewable energy certificate (REC) sales	(5,884)	(447)	(6,331)
Interest and other	(179)	623	444
Balance at December 31, 2011	$ (13,121)	$ 8,490	$ (4,631)

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

2011 Idaho General Rate Case Settlement

On June 1, 2011, Idaho Power filed a general rate case and proposed rate schedules with the IPUC, Case No. IPC-E-11-08. In its general rate case application, Idaho Power requested an additional $82.6 million in annual revenues in Idaho-jurisdictional base rates, comprised of approximately $71.3 million related to revenue requirement categories other than net power supply expenses (non-NPSE) and $11.3 million associated with net power supply expenses (NPSE).

On September 23, 2011, Idaho Power, the IPUC Staff, and other interested parties publicly filed a settlement stipulation with the IPUC resolving most of the key contested issues in the Idaho general rate case. The settlement stipulation provided for a reduction of approximately $25.8 million to the requested non-NPSE recovery, resulting in a $45.5 million increase in the non-NPSE components of Idaho-jurisdictional base rates. The settlement stipulation also provided that approximately $22.8 million of Idaho-jurisdictional revenue associated with the recovery of NPSE associated with PURPA power costs would not be included in base rates, but would instead be eligible for 100 percent recovery through the Idaho PCA mechanism if the costs are incurred. Idaho Power's requested Idaho jurisdictional base rate increase and the adjustments reflected in the settlement stipulation are summarized in the table below (in millions).

	Non-NPSE	NPSE	Total
As filed in general rate case	$ 71.3	$ 11.3	$ 82.6
Adjustments in settlement stipulation	(25.8)	(22.8)	(48.6)
Total settlement stipulation	$ 45.5	$ (11.5)	$ 34.0

The settlement stipulation provided for a 7.86 percent authorized rate of return on an Idaho-jurisdictional rate base of approximately $2.36 billion. On December 30, 2011, the IPUC issued an order approving the settlement stipulation, with new rates effective January 1, 2012. Neither the order nor the settlement stipulation specified an authorized rate of return on equity. Additional details relating to the 2011 Idaho general rate case and settlement are included in Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report.

December 2011 Idaho Settlement Agreement

On January 13, 2010, the IPUC approved a settlement agreement among Idaho Power, several of Idaho Power’s customers, the IPUC Staff, and others, in connection with a general rate case. Significant elements of the January 2010 settlement agreement included, among other items:

- a provision to share with Idaho customers 50 percent of any Idaho-jurisdiction earnings in excess of a 10.5 percent Idaho ROE in any calendar year from 2009 to 2011; and
- a provision to allow the additional amortization of accumulated deferred investment tax credits (ADITC) if Idaho Power's Idaho ROE is below 9.5 percent in any calendar year from 2009 to 2011 in its Idaho jurisdiction. Idaho Power was permitted to amortize additional ADITC in an amount up to $45 million over the three-year period, with specified annual limits.

Because Idaho Power’s Idaho ROE was between 9.5 and 10.5 percent in 2009 and 2010, the sharing and accelerated amortization provisions of the January 2010 settlement agreement were not triggered. However, recognition of income tax benefits in 2011 had a significant impact on Idaho Power's 2011 Idaho ROE and contributed to the triggering of the sharing mechanism. In accordance with the January 2010 settlement agreement, Idaho Power recorded a $27.1 million regulatory liability in 2011, reflecting 50 percent of Idaho Power's 2011 Idaho-jurisdictional earnings above a 10.5 percent Idaho ROE required to be shared with Idaho customers. The sharing and amortization provisions of the January 2010 settlement agreement terminated on December 31, 2011.

On December 27, 2011, the IPUC issued an order approving a settlement stipulation that had been executed by Idaho Power, the IPUC Staff, and one large industrial customer of Idaho Power and filed with the IPUC on December 12, 2011.
The settlement stipulation provides that:

- if Idaho Power's Idaho ROE for 2012, 2013, or 2014 is less than 9.5 percent, then Idaho Power may amortize additional ADITC to help achieve a minimum 9.5 percent Idaho ROE in the applicable year. Idaho Power would be permitted to amortize additional ADITC in an aggregate amount up to $45 million over the three-year period, but could use no more that $25 million in 2012;
- if Idaho Power's Idaho ROE for 2012, 2013, or 2014 exceeds 10.0 percent, the amount of Idaho Power's Idaho jurisdictional earnings exceeding a 10.0 percent but less than a 10.5 percent Idaho ROE for the applicable year would be shared equally between Idaho Power and its Idaho customers; and
- if Idaho Power's Idaho ROE for 2012, 2013, or 2014 exceeds 10.5 percent, the amount of Idaho Power's Idaho jurisdictional earnings exceeding a 10.5 percent Idaho ROE for the applicable year would be allocated 75 percent to Idaho Power's Idaho customers and 25 percent to Idaho Power.

In consideration of these terms, the settlement stipulation provided that Idaho Power will allocate to customers 75 percent of Idaho Power's share of 2011 Idaho-jurisdictional earnings over a 10.5 percent Idaho ROE. As a result, Idaho Power recorded a pre-tax charge to pension expense of approximately $20.3 million in 2011, representing the additional amount to be allocated to Idaho customers. After the combined effect of the 50 percent sharing mechanism in the January 2010 settlement agreement and the December 2011 settlement order that provided for additional sharing, Idaho Power retained 12.5 percent of Idaho-jurisdiction earnings exceeding a 10.5 percent Idaho ROE.

OPUC Deferral Request: On November 17, 2011, the OPUC Staff filed an application seeking authorization from the OPUC to defer in the Oregon jurisdiction $2.9 million of the benefit resulting from the uniform capitalization tax method change. Idaho Power is opposing the application, and hearings and briefs are scheduled for mid-2012.

Idaho Defined Benefit Pension Plan Contribution Recovery

In September 2010, Idaho Power made a $60 million contribution to its defined benefit pension plan. To provide for timely recovery in rates of that contribution, on March 15, 2011, Idaho Power filed an application with the IPUC requesting an increase in the amount included in base rates for recovery of the Idaho-allocated portion of Idaho Power's cash contributions to its defined benefit pension plan from the then-current amount of $5.4 million to approximately $17.1 million annually. On May 19, 2011, the IPUC approved Idaho Power’s application, with new rates effective June 1, 2011. Idaho Power also expects to continue to make additional significant cash contributions to its defined benefit pension plan through at least 2016. For estimated defined benefit pension plan funding obligations, refer to Note 11 - "Benefit Plans" to the consolidated financial statements included in this report and "Critical Accounting Policies and Estimates - Pension and Other Postretirement Benefits" in this MD&A.

The order issued by the IPUC pertaining to the December 2011 Idaho settlement agreement described above provided that Idaho Power's allocation to customers of 75 percent of Idaho Power's share of 2011 Idaho ROE over 10.5 percent would be in the form of a $20.3 million reduction to Idaho Power's pension regulatory asset to reduce the future customer obligation.

Langley Gulch Power Plant Ratemaking

On September 1, 2009, Idaho Power received pre-approval from the IPUC to include $396.6 million of construction costs in Idaho Power’s rate base when the Langley Gulch power plant achieves commercial operation. Idaho Power may request recovery of additional costs if they exceed $396.6 million, provided that the additional costs were reasonably and prudently incurred. Based on the current project status, Idaho Power estimates that the plant will be in service by July 1, 2012. Idaho Power plans to time the filing of its applications with the IPUC and OPUC for recovery of construction costs such that regulatory authority for collection of those costs is issued, and customer rates adjusted, as near as practicable to the project's commercial in-service date.

Oregon General Rate Case

On July 29, 2011, Idaho Power filed a general rate case and proposed rate schedules with the OPUC, Case No. UE 233. The filing requested a $5.8 million increase in annual Oregon jurisdictional revenues. The filing requested an authorized rate of return on equity of 10.5 percent with an Oregon retail rate base of approximately $121.9 million, and a rate of return on capital of 8.17 percent. Idaho Power, the OPUC Staff, and other interested parties executed and filed a partial settlement stipulation with the OPUC on February 1, 2012, which resolves all matters in the general rate case other than the prudence of costs associated with pollution control investments at the Jim Bridger coal plant. The settlement stipulation provides for a return on equity of 9.9 percent and an overall rate of return of 7.757 percent. If the stipulation is approved by the OPUC, Idaho Power expects that new rates will become effective on March 1, 2012. As of the date of this report, Idaho Power is unable to determine the outcome of the proceeding.

2011 Integrated Resource Plan

As a public utility under the jurisdiction of the FERC, the IPUC, and the OPUC, Idaho Power is obligated to plan for and expand its transmission system to provide requested firm transmission service to third parties, to construct and place in service sufficient generation and transmission capacity to reliably deliver resources to network customers and the company’s retail customers, and otherwise take actions to fulfill its obligation to provide safe and reliable electric service. As part of its resource planning, and in accordance with regulatory requirements, Idaho Power prepares and publishes an IRP every two years. The IRP addresses available supply-side and demand-side resource options, planning period load forecasts, potential resource portfolios, a risk analysis, and near-term and long-term action plans.

Idaho Power filed its 2011 IRP with the IPUC and OPUC on June 30, 2011. In developing its 2011 IRP, Idaho Power forecast the number of customers in Idaho Power’s service area will increase approximately 1.5 percent per year, from approximately 492,000 at the end of 2010 to over 650,000 by the end of the IRP's 20-year planning period in 2030. The 2011 IRP expected-case load forecast projects peak-hour load will grow 69 MW annually and average-system load will increase annually 29 average MW (aMW) over the 20-year planning period, with an expected-case, average annual system load of 2,362 aMW by 2030.

Idaho Power intends to meet the anticipated increase in demand through energy efficiency and demand response programs, the development of transmission capacity and additional generation resources, such as its 300 MW Langley Gulch natural gas-fired power plant currently under construction, and from the purchase of power from third parties, including from renewable energy projects and market power purchases. Idaho Power stated in the 2011 IRP that it expects energy efficiency programs to result in 233 aMW of load reduction by 2030, and that demand response programs are targeted to reduce peak summer load by 351 MW by summer 2016. The 2011 IRP also identifies transmission constraints as a significant issue for Idaho Power. Idaho Power is in the process of developing the Boardman-to-Hemingway transmission project in an effort to alleviate in part its transmission capacity constraint from the Pacific Northwest.

On December 30, 2011, the IPUC issued an order accepting Idaho Power's 2011 IRP. The order directed Idaho Power to continue to address a number of items, including: (a) comparing the risk, cost, and environmental benefits of strategies that directly reduce emissions from its resource mix to the purchase of emission offsets or offset options, (b) redoubling its efforts to realize the achievable potential for savings from efficiency and DSM programs, and (c) addressing the risks of reliance on natural gas in its resource portfolio. The order also directs Idaho Power to provide as part of its 2013 IRP additional information and/or analyses related to the Gateway West transmission project involvement, Idaho Power's proposed solar demonstration project, HCC relicensing efforts, early retirement of existing coal plants, and the quantification of transmission siting and market price risks.

PURPA Power Purchase Contracts

Pursuant to the requirements of Section 210 of PURPA, the IPUC and OPUC have each issued orders and rules regulating Idaho Power's purchase of power from cogeneration and small power production facilities. A key component of the PURPA power purchase contracts is the energy price contained within the agreements. Regulatory-mandated execution of PURPA agreements may result in Idaho Power acquiring energy it does not need at above wholesale market prices and require additional operational integration measures, thus increasing costs to Idaho Power's customers. Substantially all PURPA power purchase costs are recovered through base rates and Idaho Power's power supply cost mechanisms, and thus the primary impact of the PURPA agreements is on customer rates.

Idaho Proceedings: In response to a November 5, 2010 application filed by Idaho Power and two other electric utilities with Idaho service territories, on February 7, 2011, the IPUC issued an order temporarily reducing the eligibility cap for PURPA projects entitled to published avoided cost rates from 10 aMW to 100 kW for wind and solar PURPA projects while the IPUC further investigated the implications of large projects disaggregating into smaller projects to qualify for higher published avoided cost rates and other benefits. On June 8, 2011, the IPUC issued an order maintaining the 100 kW eligibility cap for published avoided cost rates for wind and solar PURPA projects, and initiating additional proceedings to allow the parties to investigate and analyze the methodologies used in determining the appropriate power purchase price for PURPA projects. On that same date, the IPUC issued orders disapproving 13 wind power purchase agreements. Idaho Power estimates that the payments over the lives of the disapproved agreements would have totaled approximately $1.3 billion.

Idaho Power remains engaged in proceedings at the IPUC relating to the determination of appropriate power purchase prices and other terms of PURPA power purchase agreements. The IPUC has established a timeline for various informational filings by all parties to the case, with hearings scheduled for August 2012. On January 31, 2012, Idaho Power submitted written testimony in the PURPA proceedings, in support of Idaho Power's request that the IPUC (a) change the methodology used to establish power purchase prices for PURPA projects, (b) reduce the maximum authorized PURPA power purchase agreement term from the existing 20 years to a maximum of five years, and (c) authorize a curtailment strategy that would allow Idaho Power to optimize use of its cost-effective resources.

Oregon Proceedings: In response to two filings Idaho Power made with the OPUC in January 2012, on February 14, 2012 the OPUC issued an order effectively imposing a 60 day prohibition on Idaho Power's entering into standard contracts with qualified PURPA facilities, allowing Idaho Power time to update its avoided cost rate through the IRP process prior to executing standard PURPA contracts. In the same order, the OPUC declined to reduce the eligibility cap for standard contracts from its current level of 10 MW to 100 kW. Idaho Power expects to be engaged in proceedings at the OPUC to resolve the same or similar issues being presented in the IPUC PURPA matters.

Bonneville Power Administration Residential Exchange Program

The Pacific Northwest Electric Power Planning and Conservation Act of 1980, through the Residential Exchange Program (REP), provides for access to the benefits of low-cost federal hydroelectric power to residential and small farm customers of the region's investor-owned utilities (IOUs). The program is administered by the BPA. Pursuant to agreements between the BPA and Idaho Power, benefits from the REP were passed through to Idaho Power's Idaho and Oregon residential and small farm customers in the form of electricity bill credits. However, on May 3, 2007, the U.S. Court of Appeals for the Ninth Circuit ruled that the settlement agreements entered into between the BPA and the IOUs (including Idaho Power) were inconsistent with the Northwest Power Act. As a result, on May 21, 2007, the BPA notified Idaho Power and six other IOUs that it was immediately suspending the REP payments. Subsequently, Idaho Power worked with other northwest IOUs and consumer-owned utilities, Pacific Northwest public utility commissions, and the BPA to craft an agreement so that residential and small farm customers of Idaho Power can resume sharing in the benefits of the federal Columbia River power system. The BPA approved an REP settlement agreement in a Record of Decision dated July 26, 2011 and committed the BPA to perform its obligations under the settlement agreement in accordance with its terms. Updated rates became effective January 1, 2012. Since any benefits will pass directly through to Idaho Power's eligible residential and small farm customers, the settlement is not expected to have a material effect on Idaho Power's financial condition or results of operations.

FERC Compliance Programs

The FERC has approved an extensive number of reliability standards developed by the North American Electric Reliability Corporation and the WECC, including critical infrastructure protection (CIP) standards and regional standard variations. As part of its compliance program, Idaho Power periodically reviews its operations for compliance with FERC rules, orders, and standards and self-reports compliance issues to the FERC and the WECC. Recent reports Idaho Power has submitted to the

FERC have generally focused on Standards of Conduct and Idaho Power's FERC OATT. Consistent with prior years, during the year ended December 31, 2011, Idaho Power self-reported to the FERC and received notices of alleged violations from the FERC and the WECC. Idaho Power has also received notification that the FERC intends to take no further action regarding several issues previously reported by Idaho Power.

Consistent with its historical practice, Idaho Power is working with the FERC and the WECC to resolve alleged violations and items it self-reported to the FERC and the WECC. Idaho Power is unable to predict what action, if any, the WECC or the FERC will take on those unresolved matters, but based on the nature of the potential violations Idaho Power does not expect any material adverse effect from currently alleged violations on its financial position, results of operations, or cash flows. Idaho Power plans to continue its efforts to reduce potential violations through its compliance program and its approach of self-reporting compliance issues to, and working with, the FERC and the WECC.

Relicensing of Hydroelectric Projects

Idaho Power, like other utilities that operate nonfederal hydroelectric projects on qualified waterways, obtains licenses for its hydroelectric projects from the FERC. These licenses last for 30 to 50 years depending on the size, complexity, and cost of the project. Idaho Power is actively pursuing the relicensing of the HCC and the Swan Falls project (SFP). In addition, in July 2010 Idaho Power received a license amendment to expand the Shoshone Falls hydroelectric project and to potentially extend the term of the license beyond its 2034 expiration date.

Hells Canyon Complex**:** The most significant ongoing relicensing effort is the HCC, which provides approximately 68 percent of Idaho Power's hydroelectric generating nameplate capacity and 36 percent of its total generating nameplate capacity. In July 2003, Idaho Power filed an application for a new license in anticipation of the July 2005 expiration of the then-existing license. In connection with the relicensing process, in August 2007 the FERC Staff issued a final EIS for the HCC, which the FERC will use to determine whether, and under what conditions, to issue a new license for the project. The purpose of the final EIS is to inform the FERC, federal and state agencies, Native American tribes, and the public about the environmental effects of Idaho Power's operation of the HCC. Certain portions of the final EIS involve issues that may be influenced by water quality certifications for the project under section 401 of the Clean Water Act (CWA) and formal consultations under the Endangered Species Act (ESA), which remain unresolved.

Because the HCC is located on the Snake River where it forms the border between Idaho and Oregon, Idaho Power has filed Water Quality Certification Applications, required under section 401 of the CWA, with the States of Idaho and Oregon requesting that each state certify that any discharges from the project comply with applicable state water quality standards. Water quality issues are of interest to various federal and state agencies, Native American tribes, and other parties who may provide input to the states' certification process. Section 401 of the CWA requires that a state either approve or deny a 401 water quality certification application within one year of the filing of the application or the state may be considered to have waived its certification authority under the CWA. As a consequence, Idaho Power has been filing and withdrawing its section 401 certification applications with Oregon and Idaho on an annual basis while it has been working with the states to identify measures that will provide reasonable assurance that discharges from the HCC will adequately address applicable water quality standards.

On September 13, 2007, in connection with the issuance of its final EIS, the FERC notified the NMFS and the USFWS of its determination that the licensing of the HCC was likely to adversely affect ESA-listed species under the NMFS's and USFWS's jurisdiction and requested that the NMFS and USFWS initiate formal consultation under Section 7 of the ESA on the licensing of the HCC. Each of the NMFS and USFWS responded to the FERC that the conditions relating to the licensing of the HCC were not fully described or developed in the final EIS as the measures to address the water quality effects of the project were yet to be fully defined by the Section 401 certification process pending before the Oregon and Idaho Departments of Environmental Quality. The NMFS and USFWS therefore recommended that formal consultation under the ESA be delayed until the Section 401 certification process is completed. Idaho Power continues to work with Idaho and Oregon in the development of measures to provide reasonable assurance that any discharges from the HCC will comply with applicable state water quality standards so that appropriate water quality certifications can be issued for the project, and continues to cooperate with the USFWS, NMFS, and the FERC in an effort to address ESA concerns.

Idaho Power expects the FERC to issue a license order for the HCC once the ESA consultation and the state water quality certification processes are completed. Idaho Power is currently operating under an annual license issued by the FERC and expects to continue operating under annual licenses until a new multi-year license is issued.

Swan Falls Project**:** The existing license for the SFP expired in June 2010. Idaho Power is currently operating the SFP under an annual license while its application for a multi-year license is pending before the FERC. In August 2010, the FERC issued a final EIS in connection with the relicensing of the SFP. The Snake River physa snail, a species listed as endangered under the ESA, was found in the area during the EIS review. In February 2012, the USFWS issued a biological opinion to address the project's effects on the Snake River physa snail. The biological opinion includes a provision for the incidental take of the snail for purposes of licensing and continued operation of the project. Idaho Power is required to study the status of the Snake River physa snail and its habitat within and downstream of the project area for the term of the new license, which Idaho Power anticipates will be between 30 and 50 years. Idaho Power expects the FERC to issue a license for the SFP in the second quarter of 2012.

Treatment of Relicensing Costs**:** Relicensing costs are recorded in construction work in progress until new multi-year licenses are issued by the FERC, at which time the charges are transferred to electric plant in service. Relicensing costs and costs related to new licenses will be submitted to regulators for recovery through the ratemaking process. Relicensing costs of $145 million and $5 million for HCC and SFP, respectively, were included in construction work in progress at December 31, 2011. As of the date of this report, the IPUC authorizes Idaho Power to include in its Idaho-jurisdictional rates approximately $6.5 million annually ($10.7 million grossed up for income taxes) of AFUDC relating to the HCC relicensing project, and collecting these amounts will reduce the relicensing amount submitted to regulators for recovery through the ratemaking process. Through December 31, 2011, Idaho Power has collected $31 million of AFUDC related to the HCC relicensing project through customer rates.

Shoshone Falls Expansion**:** On July 1, 2010, the FERC amended the license for the Shoshone Falls project to expand its generating capacity to approximately 61 MW. The amended license has an expiration date of 2034, but provides that the license will be extended to 2044 following completion of the proposed generation capacity expansion project. Idaho Power filed a request for a two-year schedule extension with the FERC in January 2012 as it continues to evaluate the project and the associated license requirements, costs, and operating issues, which if granted would change Idaho Power's estimated in-service date for the upgrades (if ultimately undertaken) from 2015 to 2017.

ENVIRONMENTAL MATTERS

Overview

Idaho Power is subject to regulations by federal, state, and local authorities governing the protection of the environment, including at the federal level the CAA; the CWA; the Comprehensive Environmental Response, Compensation and Liability Act; the Emergency Planning and Community Right-to-Know Act; the ESA; the Federal Land Policy and Management Act; the National Environmental Policy Act; and the Resource Conservation and Recovery Act. These laws and regulations are continuously changing and are generally becoming more restrictive. Idaho Power monitors legislative and regulatory developments at all levels of government for environmental issues, particularly those with the potential to alter the operation and productivity of power generating plants and other assets. Environmental laws and regulations may, among other things, increase the cost of operating power generation plants and constructing new facilities; require that Idaho Power install additional pollution control devices at existing generating plants; or require that Idaho Power discontinue operating certain power generation plants. While there can be no assurance of recovery, Idaho Power intends to seek recovery of any such costs through the ratemaking process.

Idaho Power co-owns three coal-fired power plants and owns two natural gas combustion turbine power plants that are subject to air quality regulation. Additionally, Idaho Power is in the process of construction and start-up of the Langley Gulch power plant, a natural gas-fired generating plant. The CAA establishes controls on the emissions from stationary sources like those owned by Idaho Power. The EPA adopts many of the standards and regulations under the CAA, while states have the primary responsibility for implementation and administration of these air quality programs. Also, the FERC licenses issued for Idaho Power's hydroelectric generating plants impose numerous environmental requirements, such as aeration of water discharged through turbines to meet dissolved gas and temperature standards in the tail waters downstream from the plants. Idaho Power monitors these issues and reports the results to the appropriate regulatory agencies. Idaho Power continues to actively monitor, evaluate, and work on water quality and air quality issues. These items are discussed in greater detail below.

Idaho Power continues to actively monitor pollution control standards as they are promulgated and their associated costs to Idaho Power as they relate to the economic and operational feasibility of generation plants. In its order acknowledging Idaho Power's 2009 IRP, the OPUC directed Idaho Power to analyze (a) any potential EPA, state, and other federal agency regulations associated with air quality, fly ash, and water that may affect Idaho Power's generation facilities, and (b) coal curtailment and the costs associated with coal plant retirement, and include the results of this analysis in its 2011 IRP. Idaho Power filed its 2011 IRP in June 2011 with the IPUC and OPUC, and the IRP contains the analysis requested by OPUC. While not currently quantifiable, Idaho Power anticipates that a number of impending EPA rulemakings addressing, among other things, ozone and fine particulate matter pollution, emissions, and disposal of coal combustion residuals could result in substantially increased operating and compliance costs.

In addition to the items below, also refer to Note 10 - "Contingencies" to the consolidated financial statements included in this report for additional information regarding certain environmental proceedings affecting Idaho Power's properties and Item 1- "Business - Environmental Regulation and Costs" in this report.

Global Climate Change and GHG Emission Intensity Reduction Goal

There is concern nationally and internationally about climate change and the possible contribution of greenhouse gas (GHG) emissions to climate change. Long-term climate change could significantly affect Idaho Power's business in a variety of ways, including:

- changes in temperature and precipitation could affect customer demand;
- extreme weather events could increase service interruptions, outages, maintenance costs, and the need for additional backup systems, and can affect the supply of, and demand for, electricity and natural gas, which may impact the price of energy commodities;
- changes in the amount and timing of snowpack and stream flows could adversely affect hydroelectric generation;
- legislative and/or regulatory developments related to climate change could affect plans and operations, including restrictions on the construction of new generation resources, the expansion of existing resources, or the operation of generation resources in general; and
- consumer preference for, and resource planning decisions requiring, renewable or low GHG-emitting sources of energy could impact usage of existing generation sources and require significant investment in new generation and transmission infrastructure.

Idaho Power does not currently operate in coastal areas and, while there may be secondary impacts, it is not directly exposed to the effects of potential sea level rises that some experts predict may result from global climate change.

Despite the current absence of a national mandatory GHG reduction program, Idaho Power is engaged in voluntary GHG emission intensity reduction efforts. In September 2009, IDACORP's and Idaho Power's boards of directors approved guidelines that established a goal to reduce the CO_2 emission intensity of Idaho Power's utility operations. Idaho Power's goal is to reduce its resource portfolio's average CO_2 emission intensity for the 2010 through 2013 time period to a level of 10 to 15 percent below Idaho Power's 2005 CO_2 emission intensity of 1,194 lbs CO_2/MWh. The guidelines are intended to reduce Idaho Power's average CO_2 emission intensity in a manner that minimizes the costs of those reductions to Idaho Power's customers. In May 2010 and May 2011, Idaho Power submitted information to the Carbon Disclosure Project, an independent, not-for-profit organization that claims the largest database of corporate climate change information in the world. Idaho Power's estimated CO_2 emission intensity (lbs/MWh) from its generation facilities as submitted to the Carbon Disclosure Project was 1,051, 1,004, 1,097, and 1,150 lbs/MWh for 2010, 2009, 2008, and 2007 respectively.

In 2008, Idaho Power and Ida-West together ranked as the 32nd lowest emitter of CO_2 per MWh produced and the 31st lowest emitter of CO_2 by tons of emissions among the nation's 100 largest electricity producers, according to a June 2010 collaborative report from Ceres, the Natural Resources Defense Council, Public Service Enterprise Group, Constellation Energy, and Entergy using publicly reported 2008 generation and emissions data. According to the report, out of the 100 companies named, Idaho Power and Ida-West together ranked as the 55th largest power producer based on fossil fuel, nuclear, and renewable energy facility total electricity generation.

Environmental Regulation

Regulation of Greenhouse Gas Emissions: In recent years, there have been a number of bills introduced in the U.S. Congress relating to GHG emissions, renewable energy, energy efficiency, carbon capture and sequestration, and other matters. However, given the complexities of this form of legislation and other competing legislative priorities, the timing and elements of any future legislation addressing GHG emission reduction requirements are uncertain. There are also state and regional initiatives (including the Western Regional Climate Action Initiative) considering market-based mechanisms to reduce GHG emissions. Further, in support of international efforts to reduce GHG emissions, in January 2010 the Obama Administration pledged to cut GHG emissions in the United States from 2005 levels by 17 percent by 2020 and 80 percent by 2050. However, any international treaty creating mandatory GHG emission reduction requirements in the United States would require Congressional approval.

In June and December 2010, the EPA issued final rules regulating GHG emissions through its pre-construction and operating permit programs under the CAA. These rules are referred to as the "Tailoring Rule" and GHG Permitting Rules. The first phase of the rules took effect in January 2011 and required imposition of Best Available Control Technology (BACT) for GHG emissions if a new major source or modification of an existing major source is projected to result in GHG emissions of at least 75,000 tons per year (CO_2 equivalent). In addition, existing major sources were required to include applicable requirements relating to GHGs in their operating permits when the permits are renewed or the major source is modified. Idaho Power believes that its owned and co-owned generation plants are in compliance with the new GHG emission regulations.

In August 2007, the Oregon legislature enacted legislation establishing goals for the reduction of GHG emissions, which sought to cease the growth of Oregon GHG emissions by 2010, and seek to (a) by 2020, reduce GHG levels to 10 percent below 1990 levels; and (b) by 2050, reduce GHG levels to at least 75 percent below 1990 levels. The legislation also calls for state government-developed policy recommendations in the future to assist in the monitoring and achievement of these goals.

Idaho Power will continue to monitor and evaluate proposed international, federal, state, and regional GHG legislation or initiatives as well as judicial decisions that could affect its generating facilities and operations. Some recent initiatives regarding GHG emissions contemplate market-based compliance programs, such as cap-and-trade programs or emission offsets. The regulation of GHG emissions under the CAA could result in GHG emission limits on stationary sources that do not provide market-based compliance options. Such a program could raise uncertainty about the future viability of fossil fuels, specifically coal, as an economical energy source for new and existing electric generation facilities because new technologies for reducing CO_2 emissions from coal, including carbon capture and storage, are still in the development stage and are not yet proven. Emission standards could require significant increases in capital expenditures and operating costs, which may accelerate the retirement of older, less-efficient coal-fired units.

There are financial, regulatory, and logistical uncertainties related to GHG reductions and the implementation of renewable energy mandates. The impact on Idaho Power of currently proposed legislation relating to GHG emissions would depend on a variety of factors, including the specific GHG emissions limits or renewable energy requirements, the timing of implementation of these limits or requirements, the level of emissions allowances allocated and the level that must be purchased, the purchase price of emissions allowances, the development and commercial availability of technologies for renewable energy and for the reduction of emissions, the degree to which offsets may be used for compliance, provisions for cost containment (if any), the impact on coal and natural gas prices, and cost recovery through rates. Accordingly, Idaho Power cannot meaningfully predict the effect on its results of operations, financial position, or cash flows of any GHG emission, renewable energy mandate, or other global climate change requirements that may be adopted, although the costs to implement and comply with any such requirements could be substantial. Idaho Power would seek to recover these costs and expenditures from customers as costs of doing business but is unable to predict whether it would be permitted to recover some or all of the increased costs and expenditures from customers through rates.

In its 2011 IRP, Idaho Power did not include any new conventional coal resources in the resource portfolio due to the uncertainty regarding future GHG regulations. IDACORP and Idaho Power's boards of directors continue to review environmental issues on a regular basis and in connection with the review of the companies' strategic plans. The boards of directors are also periodically informed of any new material environmental issues, including updates on any proposed legislation.

Renewable Portfolio Standards: Legislation has been introduced in the U.S. Congress that would require utilities to obtain a specified percentage of their electricity from renewable sources, commonly referred to as a "renewable portfolio standard" or "RPS." However, as of the date of this report no federal RPS is in effect. Idaho Power will be required to comply with a 10 percent RPS in Oregon beginning in 2025, and Idaho Power expects to meet these requirements with the RECs from the Elkhorn Valley wind project. No RPS requirement currently exists in Idaho. Idaho Power continues to monitor proposed federal RPS legislation and the possibility of additional state RPS legislation.

Utility Maximum Achievable Control Technology (MACT): In April 2010, the U.S. District Court for the District of Columbia approved a timetable that required the EPA to finalize a standard to control mercury emissions from coal-fired power plants by November 2011. In March 2011, the EPA released the proposed Utility Maximum Achievable Control Technology rule (Utility MACT Rule) to control emissions of mercury and other hazardous air pollutants (HAPs) from coal- and oil-fired electric utility steam generating units (EGUs) under the federal CAA. In the same notice, the EPA further proposed to revise the NSPS for fossil fuel-fired EGUs. In December 2011, the EPA finalized the Utility MACT Rule. The final Utility MACT Rule remains largely the same as the proposal. The final regulation imposes maximum achievable control technology and NSPS standards on all coal-fired EGUs and replaces the former Clean Air Mercury Rule. Specifically, the final regulation sets numeric emission limitations on coal-fired EGUs for total particulate matter (a surrogate for non-mercury HAPs), hydrogen chloride, and mercury. In addition, the final regulation imposes a work practice standard for organic HAPs, including dioxins and furans. The final regulation also sets work-practice standards to reduce emissions during start-up and shut-down. For the revised NSPS, for EGUs commencing construction of a new source after publication of the regulation, the EPA has established amended emission limitations for particulate matter, sulfur dioxide, and nitrogen oxides. Mercury continuous emission monitoring systems have been installed on all of the coal-fired units at the Jim Bridger, Boardman, and Valmy generating plants. However, Idaho Power is in the process of determining how these regulations will impact the Bridger, Boardman, and Valmy generating plants and what additional controls, if any, will need to be installed in order to comply with the regulations. Based on its evaluation as of the date of this report, Idaho Power does not foresee any plant closures due to the Utility MACT Rule and expects related compliance costs will not be substantial.

National Ambient Air Quality Standards (NAAQS): In July 1997, the EPA adopted new NAAQS for ozone (8-hour ozone standard) and fine particulate matter of less than 2.5 micrometers in diameter (PM2.5 standard). In December 2006, the EPA revised the NAAQS for PM2.5. This new standard is the subject of a legal challenge by a number of groups. However, all of the counties in Idaho, Nevada, Oregon, and Wyoming where Idaho Power's power plants are currently located were designated as meeting attainment with the revised PM2.5 NAAQS. In January 2010, the EPA adopted a new NAAQS for NO_2 at a level of 100 parts per billion averaged over a 1-hour period. In addition, in June 2010 the EPA adopted a new NAAQS for SO_2 at a level of 75 parts per billion averaged over a one-hour period. The various states and the EPA have not yet completed the designation of areas as attaining or not attaining these new NAAQS. As a result, Idaho Power is unable to predict what impact the adoption and implementation of these standards may have on its operations.

Regional Haze – Best Available Retrofit Technology (RH BART): In accordance with federal regional haze rules, coal-fired utility boilers are subject to RH BART if they were built between 1962 and 1977 and affect any Class I areas. This includes all four units at the Jim Bridger plant and the Boardman plant. The two units at the Valmy plant were constructed after 1977 and are not, as of the date of this report, subject to the federal regional haze rule. The Wyoming Department of Environmental

Quality (WDEQ) and the Oregon Department of Environmental Quality (ODEQ) have conducted assessments of the Jim Bridger and Boardman plants pursuant to an RH BART process. These states have also evaluated the need for additional controls at Jim Bridger and Boardman to achieve reasonable progress toward a long term strategy beyond RH BART to reduce regional haze in Class I areas to natural conditions by the year 2064.

Jim Bridger Plant: In December 2009, the WDEQ issued a RH BART permit to PacifiCorp for the Jim Bridger plant. The WDEQ determined that low NOx burners with over-fire air is RH BART for NOx for all four Bridger units and that RH BART is not required for SO_2 for the Jim Bridger plant. As part of the WDEQ's long term strategy for regional haze, the permit requires that PacifiCorp install selective catalytic reduction (SCR) for NOx control at Jim Bridger Units 3 and 4 by December 31, 2015 and December 31, 2016, respectively, and submit an application by January 15, 2015 to install add-on NOx controls at Jim Bridger Units 1 and 2 by December 31, 2023. PacifiCorp is already in the process of installing low NOx burners and SO_2 scrubber upgrades at the Jim Bridger plant. The SO_2 scrubber upgrade project has been completed on all four Jim Bridger units. Idaho Power expects to spend approximately $2 million in 2012 to complete these pollution control projects. Idaho Power's estimated share of the cost to install SCR on Jim Bridger Units 3 and 4 is $120 million. Installation of SCR also could require extended maintenance outages. Design and cost estimates for add-on NOx controls at Jim Bridger Units 1 and 2 are not yet available.

In February 2010, PacifiCorp filed an administrative appeal of the Jim Bridger RH BART permit with the Wyoming Environmental Quality Council (WEQC). PacifiCorp argued that the WDEQ lacked the legal and technical basis to require the SCR and add-on NOx controls required by the permit. In November 2010, PacifiCorp and the WDEQ signed a settlement agreement under which PacifiCorp has agreed to install SCR, alternative add-on NOx controls, or otherwise achieve a 0.07 lb/mmBtu 30-day rolling average NOx emission rate by December 31, 2015 for Unit 3 and December 31, 2016 for Unit 4. In addition, PacifiCorp has agreed to install SCR, alternative add-on NOx controls, or otherwise achieve a 0.07 lb/mmBtu 30-day rolling average NOx emission rate by December 31, 2021 for Unit 2 and December 31, 2022 for Unit 1. The settlement agreement is conditioned on the EPA ultimately approving those portions of the Wyoming Regional Haze State Implementation Plan (RH SIP) that are consistent with the terms of the settlement agreement. In light of the settlement agreement, PacifiCorp received a revised RH BART permit for Jim Bridger on November 24, 2010. In September 2011, a federal district court in Colorado approved a consent decree in the case of *Wildearth Guardians v. Jackson* pursuant to which the EPA must either propose to approve the Wyoming RH SIP or propose an alternate Federal Implementation Plan (FIP) by April 15, 2012. In addition, the EPA must either grant final approval to the Wyoming RH SIP or finalize an RH FIP for Wyoming by October 15, 2012.

Boardman Power Plant: Following the introduction of various plans and an extensive public process, in December 2010 the OEQC approved a plan to cease coal-fired operations at the Boardman power plant not later than December 31, 2020. The rules implementing the plan were approved by the EPA and published in the Federal Register in July 2011, and require the installation of a number of emissions controls. The new rules repeal the OEQC's 2009 Best Available Retrofit Technology rule, which would have allowed continued operation of the Boardman plant through at least 2040 with installation of a more extensive suite of emissions controls. The estimated combined total capital cost of the required controls under the plan approved by the OEQC is approximately $60 million. Idaho Power is a 10 percent owner of the Boardman plant, and thus Idaho Power's estimated share of the capital cost is $6 million, which is in addition to normal capital expenditures and maintenance costs. As of December 31, 2011, Idaho Power had paid $2.8 million of its total estimated share of the capital cost.

In September 2011, the federal district court in Oregon approved a consent decree that settled a citizen suit brought by the Sierra Club against PGE alleging certain violations of the requirements of the CAA at the Boardman plant. Under the terms of the settlement, beginning in 2015 through 2020 PGE has agreed to cap and reduce annual sulfur dioxide emissions to levels lower than those specified in the OEQC plan described above and further agreed to pay certain public interest groups a total of $2.5 million for various air quality projects.

The scheduled 2020 shutdown of coal-fired operations at the Boardman plant results in increased revenue requirements for Idaho Power related to accelerated depreciation expense, additional plant investments, and decommissioning costs. As a result, in response to an application Idaho Power filed in September 2011, on February 14, 2012 the IPUC issued an order accepting Idaho Power's regulatory accounting and cost recovery plan associated with the early shut-down and approving the establishment of a balancing account whereby incremental costs and benefits associated with the early shut-down will be tracked for recovery in a subsequent proceeding. On February 15, 2012, Idaho Power filed an application with the IPUC requesting a $1.6 million annual increase in Idaho jurisdiction base rates to recover the incremental Idaho jurisdictional annual revenue deficiency associated with early shut-down. As of December 31, 2011, Idaho Power's net book value in the Boardman plant was approximately $25.9 million with annual depreciation of approximately $1.3 million.

New Source Review (NSR): Since 1999, the EPA and the U.S. Department of Justice have been pursuing a national enforcement initiative focused on the compliance status of coal-fired power plants with the NSR permitting requirements and NSPS of the CAA. This initiative has resulted in both enforcement litigation and significant settlements with a large number of public utilities and other owners of coal-fired power plants across the country. The EPA sent information requests under the CAA, requesting information relevant to NSR and NSPS compliance, to the Jim Bridger plant in 2003, the Valmy plant in 2009, and the Boardman plant in 2008 with a follow up request for information in 2009. In September 2010, the EPA issued a Notice of Violation to PGE, alleging that PGE has violated the NSPS under Section III of the CAA and operating permit requirements under Title V of the CAA at the Boardman coal-fired plant as a result of certain modifications made to the plant in 1998 and 2004. See Note 10 - "Contingencies" to the consolidated financial statements included in this report for a discussion of the Boardman EPA Notice of Violation.

Coal Combustion Residuals (CCRs): In December 2008, the breach of a dike at the Tennessee Valley Authority's Kingston Station resulted in a spill of several million cubic yards of ash into a nearby river and onto private properties. In June 2010, the EPA proposed regulations pursuant to the Resource Conservation and Recovery Act governing the disposal and management of CCRs. The EPA requested comments on two options for regulating CCRs. The first would regulate CCRs as a new "special waste" subject to many of the requirements for hazardous waste, while the second would regulate CCRs in a manner similar to typical solid waste, subject to fewer and less stringent environmental requirements. The EPA initiated a public comment period and held public hearings, which ended in November 2011. Either of the EPA's proposed options represents a shift toward more comprehensive and potentially more expensive requirements for CCRs disposal and management. If this or other new legislation or regulations increase the cost of managing and disposing of CCRs or create additional liability with respect to historic disposal practices, they could have an adverse impact on Idaho Power's consolidated financial position, results of operations, or cash flows. However, the financial and operational consequences cannot be determined until final legislation is passed or regulations are enacted.

Polychlorinated Biphenyls (PCBs): In April 2010, the EPA issued an advance notice of proposed rulemaking pursuant to the Toxic Substances Control Act regarding the use of PCBs. The EPA is considering revisiting the use authorization allowing the continued use of PCBs in equipment. If new regulations require the replacement of existing equipment, they could have an adverse effect on Idaho Power's consolidated financial position, results of operations, or cash flows. However, the financial and operational consequences cannot be determined until final regulations are enacted. Idaho Power currently records asset retirement obligation liabilities and associated regulatory assets for the estimated retirement costs of equipment containing PCBs. Proposed regulations could accelerate Idaho Power's estimated timing of the retirements of equipment with PCBs.

Clean Water Act Section 316(b): In March 2011, the EPA issued a proposed rule that would establish requirements under section 316(b) of the CWA for all existing power generating facilities and existing manufacturing and industrial facilities that withdraw more than 2 million gallons per day (MGD) of water from waters of the U.S. and use at least 25 percent of the water they withdraw exclusively for cooling purposes. The proposed rules would establish national requirements applicable to the location, design, construction, and capacity of cooling water intake structures at these facilities by setting requirements that reflect the best technology available (BTA) for minimizing adverse environmental impact. The existing facility may choose one of two options for meeting BTA requirements for impingement mortality under this proposed rule. The owner or operator may monitor to show the specified performance standards for impingement mortality of fish and shellfish have been met, or they may demonstrate that the intake velocity meets specified design criteria. For entrainment mortality, this proposed rule establishes requirements for studies and information as part of the permit application, and then establishes a process by which the BTA for entrainment mortality would be implemented at each facility. Idaho Power expects the draft rule to be issued in the first half of 2012. Based on the qualification criteria, Idaho Power expects that the new requirements would apply to the Jim Bridger plant, but is unable to determine the potential increased costs that may result from implementation of the rule until final rules are issued and it has performed cost studies.

Public Nuisance-Related Suits for GHGs

In December 2010, the U.S. Supreme Court granted certiorari in *Connecticut v. American Electric Power, Inc*., to review the opinion from the U.S. Court of Appeals for the Second Circuit granting plaintiffs standing to bring climate change-related public nuisance suits against six major emitters of greenhouse gases (GHGs). In June 2011, the U.S. Supreme Court held that federal courts do not have jurisdiction to hear federal common law nuisance claims relating to GHG emissions, because the legal authority to regulate GHGs has been delegated by Congress to the EPA, not to federal courts. Even though the Court rejected the merits of the plaintiffs' claim, the Court nevertheless held that the plaintiffs had the requisite legal standing to bring the claims. Finally, the Court remanded to the Second Circuit the issue of whether state common law nuisance claims would also be barred by the federal CAA. Accordingly, the decision of the Supreme Court in this case does not eliminate the potential for future nuisance-related suits based on GHG emissions.

Renewable Energy Certificates and Emission Allowances

Pursuant to an IPUC order, Idaho Power is selling its near-term RECs and returning to customers their share (shared 95% with customers in the Idaho jurisdiction) of those proceeds through the PCA. For the year ended December 31, 2011, Idaho Power's REC sales totaled $6.5 million. Idaho Power has sold all of its 2010 and earlier vintage RECs. Idaho Power has sold a portion of its 2011 RECs and intends to continue selling its 2011 and later RECs as they are generated and become available for sale. Ordinarily, Idaho Power does not receive the RECs associated with PURPA projects.

Endangered Species

The listing of a species as threatened or endangered may have an adverse impact on Idaho Power's ability to construct generation, transmission, or distribution facilities or to relicense its hydroelectric projects. Several notable matters pertaining to threatened or endangered species and affecting Idaho Power are discussed below.

***Slickspot Peppergrass*:** This southwestern Idaho plant species was listed as threatened by the USFWS in 2009. While critical habitat for the plant was not designated at the time of listing, approximately 98 percent of the plant species is located on federal land owned by the BLM and the U.S. Department of Defense. Parts of the Boardman-to-Hemingway and Gateway West 500-kV transmission lines will cross BLM land. This listing will add an additional requirement and species for consideration in the ESA Section 7 consultation. A Section 7 consultation is a process used to determine a proposed action's effects on any ESA-listed species that may be within the project area. This listing may increase the expense and delay the timing of permitting for these projects.

***Sage Grouse*:** The sage grouse is considered a "candidate species" under the ESA, which allows land management agencies to implement additional conservation measures in an effort to prevent a formal ESA listing. In March 2010, the USFWS announced that listing of the greater sage grouse as threatened or endangered under the ESA is warranted, but precluded by higher priority listing actions. On February 2, 2012, a federal district court in Idaho issued an order denying a request to expedite the listing of the sage grouse under the ESA. As a result, the USFWS has until 2015 to make a final listing determination under the ESA. On February 6, 2012, the same court issued an order holding that the BLM had violated the National Environmental Policy Act and other federal laws in connection with the granting of livestock grazing permit renewals in sage grouse habitat. Due to the presence of sage grouse in the vicinity, siting of the Boardman-to-Hemingway and Gateway West 500-kV transmission lines has required more extensive, costly, and time consuming evaluation, permitting, and engineering. Any required additional conservation measures may increase the costs of existing operations and impact the cost and timing of siting, permitting, and construction of the Boardman-to-Hemingway and Gateway West transmission lines and other construction and transmission projects. Listing of the greater sage grouse as threatened or endangered under the ESA would add an additional requirement and species for consideration in ESA Section 7 consultations for those projects, and may increase the expense and adversely affect the cost and timing of those projects.

***Hells Canyon Project*:** In 2007, the FERC requested initiation of formal consultation under the ESA with the National Marine Fisheries Service (NMFS) and the USFWS regarding potential effects of HCC relicensing on several listed aquatic and terrestrial species. Formal consultation has not yet been initiated and NMFS and USFWS continue to gather and consider information relative to the effects of relicensing on relevant species. Idaho Power continues to cooperate with the USFWS, the NMFS, and the FERC in an effort to address ESA concerns. Idaho Power may be required to modify operations pursuant to the biological opinion that will result from formal consultation. However, the issuance of a final biological opinion during 2012 is unlikely.

***Bliss and Lower Salmon Falls Projects*:** As part of a settlement agreement, Idaho Power has finalized a snail protection plan for the Bliss and Lower Salmon Falls projects in cooperation with the USFWS. Idaho Power has filed applications with the FERC to amend the licenses for the projects that will maintain operating flexibility at both projects for the remainder of their licenses. The FERC and USFWS are conducting an ESA Section 7 consultation on two ESA listed snails, the Bliss Rapids snail and the Snake River physa snail. Idaho Power has been working closely with USFWS to develop the necessary biological information to complete the consultation. A biological assessment for the Snake River physa snail, jointly developed between the USFWS and Idaho Power, was filed with the FERC in September 2011. The biological assessment evaluates the potential impacts of the license amendment on the Snake River physa snail. Idaho Power anticipates that the FERC will request formal consultation with the USFWS during the second half of 2012. The USFWS will then develop a biological opinion on the effects of load-following on both types of snails.

***Swan Falls Project*:** In August 2010, the FERC issued a final EIS in connection with the relicensing of the SFP. The Snake River physa snail, a species listed as endangered under the ESA, was found in the area during the EIS review. While the biological opinion includes a provision for the incidental take of the snail, Idaho Power is required to study the status of the Snake River physa snail and its habitat within and downstream of the project area for the term of the new license.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

When preparing financial statements in accordance with generally accepted accounting principles (GAAP), IDACORP's and Idaho Power's management must apply accounting policies and make estimates that affect the reported amounts of assets, liabilities, revenues, and expenses and related disclosure of contingent assets and liabilities. These estimates often involve judgment about factors that are difficult to predict and are beyond management's control. Management adjusts these estimates based on historical experience and on other assumptions and factors that are believed to be reasonable under the circumstances. Actual amounts could materially differ from the estimates.

Management believes the following accounting policies and estimates are the most critical to the portrayal of their financial condition and results of operations and require management's most difficult, subjective, or complex judgments, often as a result of the need to make estimates about the effect of matters that are inherently uncertain and may change in subsequent periods.

Accounting for Rate Regulation

Entities that meet specific conditions are required by GAAP to reflect the impact of regulatory decisions in their consolidated financial statements and to defer certain costs as regulatory assets until matching revenues can be recognized. Similarly, certain items may be deferred as regulatory liabilities. Idaho Power must satisfy three conditions to apply regulatory accounting: (1) an independent regulator must set rates; (2) the regulator must set the rates to cover specific costs of delivering service; and (3) the service territory must lack competitive pressures to reduce rates below the rates set by the regulator.

Idaho Power has determined that it meets these conditions, and its financial statements reflect the effects of the different rate making principles followed by the jurisdictions regulating Idaho Power. The primary effect of this policy is that Idaho Power has recorded $987 million of regulatory assets and $362 million of regulatory liabilities at December 31, 2011. Idaho Power expects to recover these regulatory assets from customers through rates and refund these regulatory liabilities to customers through rates, but recovery or refund is subject to final review by the regulatory bodies. If future recovery or refund of these amounts ceases to be probable, or if Idaho Power determines that it no longer meets the criteria for applying regulatory accounting, or if accounting rules change to no longer provide for regulatory assets and liabilities, Idaho Power would be required to eliminate those regulatory assets or liabilities, unless regulators specify some other means of recovery or refund. Either circumstance could have a material effect on Idaho Power's results of operations and financial position.

Income Taxes

IDACORP and Idaho Power use judgment and estimation in developing the provision for income taxes and the reporting of tax-related assets and liabilities. The interpretation of tax laws can involve uncertainty, since tax authorities may interpret such laws differently. Actual income taxes could vary from estimated amounts and may result in favorable or unfavorable impacts to net income, cash flows, and tax-related assets and liabilities.

Idaho Power's deferred income taxes for plant-related items (commonly referred to as normalized accounting) are primarily provided for the difference between income tax depreciation and book depreciation used for financial statement purposes. Unless contrary to applicable income tax guidance, deferred income taxes are not provided for those income tax timing differences where the prescribed regulatory accounting methods direct Idaho Power to recognize the tax impacts currently for rate making and financial reporting.

In September 2009, the IRS issued IDD #5, which discusses the IRS's compliance priorities and audit techniques related to the allocation of mixed service costs in the uniform capitalization methods of electric utilities. Since that time, the IRS and Idaho Power agreed to a method consistent with the IDD guidance and changed Idaho Power's uniform capitalization method. In 2010, Idaho Power provided a current uncertain tax position liability equal to the net tax benefit recorded for the method change until the agreement with the IRS was approved by the Joint Committee. This approval occurred in the third quarter of 2011, which effectively settled the issue for financial reporting purposes. No material uncertain tax positions remained at December 31, 2011.

Asset Impairment

Available-for-sale Securities: Idaho Power is required to evaluate available-for-sale securities periodically to determine whether a decline in fair value below cost is other than temporary. If the decline in fair value is other than temporary, the cost of the investment is written down to fair value and the loss is recorded as a realized loss. Two significant factors that are considered when evaluating investments for impairment are the length of time and the extent to which the market value has been less than cost.

Idaho Power has investments in four mutual funds that experienced a significant decline in fair value in 2008. Idaho Power's investments had lost between 32 percent and 43 percent of their value, primarily during the stock market downturn in September and October 2008, and had been in loss positions from 6 to 12 months at December 31, 2008. Because of the severity of the declines in value, Idaho Power determined that the loss in value was other-than-temporary and recorded a pre-tax loss of $6.8 million in the fourth quarter of 2008. At December 31, 2011 and 2010, the fair values of these investments were at or above their new cost bases and no impairment was recorded.

Equity-Method Investments: IFS has affordable housing investments with a net book value of $63 million at December 31, 2011, and Ida-West has investments in four joint ventures that own electric power generation facilities. Except for one investment which is consolidated, these investments are accounted for under the equity method of accounting. The standard for determining whether impairment must be recorded for these investments is whether the investment has experienced a loss in value that is considered an other-than-temporary decline in value. Impairment analyses are performed on these investments when indicators of impairment are noted. An immaterial impairment was recorded on one of the Ida-West joint ventures in 2011, and no impairments were recorded in 2010 or in 2009. These estimates required IDACORP to make assumptions about future revenues, cash flows, and other items that are inherently uncertain. Actual results could vary significantly from the assumptions used, and the impact of such variations could be material.

Pension and Other Postretirement Benefits

Idaho Power maintains a tax-qualified, noncontributory defined benefit pension plan covering most employees, an unfunded nonqualified deferred compensation plan for certain senior management employees and directors called the Senior Management Security Plan (SMSP), and a postretirement benefit plan (consisting of health care and death benefits).

The costs IDACORP and Idaho Power record for these plans depend on the provisions of the plans, changing employee demographics, actual returns on plan assets, and several assumptions used in the actuarial valuations from which the expense is derived. The key actuarial assumptions that affect expense are the expected long-term return on plan assets and the discount rate used in determining future benefit obligations. Management evaluates the actuarial assumptions on an annual basis, taking into account changes in market conditions, trends, and future expectations. Estimates of future stock market performance, changes in interest rates, and other factors used to develop the actuarial assumptions are uncertain, and actual results could vary significantly from the estimates.

The assumed discount rate is based on reviews of market yields on high-quality corporate debt. Specifically, IDACORP and Idaho Power determined the discount rate for each plan through the construction of hypothetical portfolios of bonds selected from high-quality corporate bonds available as of December 31, 2011, with maturities matching the projected cash outflows of the plans. The discount rate used to calculate the 2012 pension expense will be decreased to 4.9 percent from the 5.4 percent used in 2011.

Rate-of-return projections for plan assets are based on historical risk/return relationships among asset classes. The primary measure is the historical risk premium each asset class has delivered versus the return on 10-year U.S. Treasury Notes. This historical risk premium is then added to the current yield on 10-year U.S. Treasury Notes, and the result provides a reasonable prediction of future investment performance. Additional analysis is performed to measure the expected range of returns, as well as worst-case and best-case scenarios. Based on the current interest rate environment, current rate-of-return expectations are lower than the nominal returns generated over the past 20 years when interest rates were generally much higher. The long-term rate of return used to calculate the 2012 pension expense will be 7.75 percent, compared to the 8.25 percent rate used for 2011.

Gross pension and other postretirement benefit expense for these plans totaled $39 million, $39 million, and $40 million for the years ended December 31, 2011, 2010, and 2009, respectively, including amounts allocated to capitalized labor and amounts deferred as regulatory assets. For 2012, gross pension and other postretirement benefit costs are expected to total approximately $52 million, which takes into account the change in the discount rate noted above, as well as a decrease in expected return on plan assets. No changes were made to the other key assumptions used in the actuarial calculation.

Had different actuarial assumptions been used, pension expense could have varied significantly. The following table reflects the sensitivities associated with changes in the discount rate and rate-of-return on plan assets actuarial assumptions on historical and future pension and postretirement expense:

	Discount rate		Rate of return	
	2012	2011	2012	2011
	(millions of dollars)			
Effect of 0.5% increase on net periodic benefit cost	$ (5.7)	$ (4.8)	$ (2.2)	$ (2.1)
Effect of 0.5% decrease on net periodic benefit cost	6.6	5.2	2.2	2.1

Additionally a 0.5 percent increase in the plans' discount rates would have resulted in a $55 million decrease in the combined benefit obligations of the plans as of December 31, 2011. A 0.5 percent decrease in the plans' discount rates would have resulted in a $61 million increase in the combined benefit obligations of the plans as of December 31, 2011.

No cash contributions were made to the defined benefit pension plan in 2009. Contributions of $60 million and $18.5 million were made in 2010 and 2011, respectively. Contributions required to be made during 2012 are estimated to be $34 million. Payments of $44 million, $44 million, $42 million, and $42 million are estimated to be due in 2013, 2014, 2015, and 2016, respectively. Under the SMSP, Idaho Power makes payments directly to participants in the plan. Benefit payments are expected to be $3.6 million in 2012 and averaged $3.3 million per year from 2009 to 2011. Postretirement benefit plan contributions are expected to be $3.7 million in 2012, and averaged $2.3 million from 2009 to 2011.

The IPUC has authorized Idaho Power to account for its defined benefit pension plan expense on a cash basis, and to defer and account for accrued pension expense as a regulatory asset. The IPUC acknowledged that it is appropriate for Idaho Power to seek recovery in its revenue requirement of reasonable and prudently incurred pension expense based on actual cash contributions. In 2007, Idaho Power began deferring pension expense to a regulatory asset account to be matched with revenue when future pension contributions are recovered through rates. At December 31, 2011, $58 million of expense was deferred as a regulatory asset. Approximately $22 million is expected to be deferred in 2012. Idaho Power recorded pension expense in 2011, 2010, and 2009 of $34 million, $5 million, and $1 million, respectively.

Refer to Note 11 – “Benefit Plans” of the consolidated financial statements included in this report for additional information relating to pension and postretirement benefit plans.

Contingent Liabilities

An estimated loss from a loss contingency is charged to income if (a) it is probable that a liability had been incurred at the date of the financial statements and (b) the amount of the loss can be reasonably estimated. If a probable loss cannot be reasonably estimated, no accrual is recorded but disclosure of the contingency in the notes to the financial statements is required. Gain contingencies are not recorded until realized.

IDACORP and Idaho Power have a number of unresolved issues related to regulatory and legal matters. If the recognition criteria have been met, liabilities have been recorded. Estimates of this nature are highly subjective and the final outcome of these matters could vary significantly from the amounts that have been included in the financial statements.

RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

There have been no recently issued accounting pronouncements that have had or are expected to have a material impact on IDACORP's or Idaho Power's results of operations or financial condition. See Note 1 - “Summary of Significant Accounting Policies” to the consolidated financial statements included in this report for a summary of significant accounting policies.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

IDACORP and Idaho Power are exposed to market risks, including changes in interest rates, changes in commodity prices, credit risk, and equity price risk. The following discussion summarizes these risks and the financial instruments, derivative instruments, and derivative commodity instruments sensitive to changes in interest rates, commodity prices, and equity prices that were held at December 31, 2011.

Interest Rate Risk

IDACORP and Idaho Power manage interest expense and short- and long-term liquidity through a combination of fixed rate and variable rate debt. Generally, the amount of each type of debt is managed through market issuance, but interest rate swap and cap agreements with highly rated financial institutions may be used to achieve the desired combination.

***Variable Rate Debt*:** As of December 31, 2011, IDACORP and Idaho Power had $78.3 million and $24.1 million, respectively, in net floating-rate debt. The fair market value of this debt was $78.3 million and $24.1 million, respectively. Assuming no change in financial structure, if variable interest rates were to average one percentage-point higher than the average rate on December 31, 2011, interest rate expense would increase and pre-tax earnings would decrease by approximately $0.8 million for IDACORP and $0.2 million for Idaho Power.

***Fixed Rate Debt*:** As of December 31, 2011, IDACORP and Idaho Power each had $1.5 billion in fixed rate debt, with a fair market value equal to $1.7 billion. These instruments are fixed rate and, therefore, do not expose the companies to a loss in earnings due to changes in market interest rates. However, the fair value of these instruments would increase by approximately $193 million for both IDACORP and Idaho Power if interest rates were to decline by one percentage point from their December 31, 2011 levels.

Commodity Price Risk

Idaho Power's exposure to changes in commodity prices is related to its ongoing utility operations that produce electricity to meet the demand of its retail electric customers. To supplement its generation resources and balance its supply of power with the demand of its retail customers, Idaho Power participates in the wholesale marketplace. These purchased power arrangements allow Idaho Power to respond to fluctuations in the demand for electricity and variability in generating plant operations. Idaho Power also enters into arrangements for the purchase of fuel for natural gas and coal-fired generating plants. Idaho Power anticipates that the additional volume of natural gas needed to operate the Langley Gulch power plant will increase its exposure in the future to natural gas commodity price risk. These contracts for the purchase of power and fuel expose Idaho Power to commodity price risk.

A number of factors associated with the structure and operation of the energy markets influence the level and volatility of prices for energy commodities and related derivative products. The weather is a major uncontrollable factor affecting the local and regional demand for electricity and the availability and cost of production. Other factors include the occurrence and timing of demand peaks due to seasonal, daily, and hourly power demand; power supply; power transmission capacity; changes in federal and state regulation and compliance obligations; fuel supplies; and market liquidity.

Idaho Power’s exposure to commodity price risk is largely offset by the PCA mechanisms in Idaho and Oregon. Therefore, the primary objectives of Idaho Power’s energy purchase and sale activity are to meet the demand of retail electric customers, maintain appropriate physical reserves to ensure reliability, and make economic use of temporary surpluses that may develop. Idaho Power has adopted a risk management program, which has been reviewed and accepted by the IPUC, designed to reduce exposure to power supply cost-related uncertainty, further mitigating commodity price risk. Idaho Power’s Energy Risk Management Policy (Policy) and associated standards implementing the Policy describe a collaborative process with customers and regulators via a committee called the Customer Advisory Group (CAG). The Risk Management Committee (RMC), comprised of selected Idaho Power officers and other senior staff, oversees the risk management program. The RMC is responsible for communicating the status of risk management activities to the Idaho Power Board of Directors and to the CAG, and Idaho Power’s Audit Committee is responsible for approving the Policy and associated standards. The RMC is also responsible for conducting an ongoing general assessment of the appropriateness of Idaho Power’s strategies for energy risk management activities. In its risk management process, Idaho Power considers both demand-side and supply-side options consistent with its IRP. The primary tools for risk mitigation are physical and financial forward power transactions and fueling alternatives for utility-owned generation resources. Idaho Power does not engage in trading activities for non-retail purposes.

The Policy requires monitoring monthly volumetric electricity position and total monthly dollar (net power supply cost) exposure on a rolling 18-month forward view. The Power Supply business unit produces and evaluates projections of the operating plan based on factors such as forecasted resource availability, stream flows, and load, and orders risk mitigating actions, including resource optimization and hedging strategies, dictated by the limits stated in the Policy to bring exposures within pre-established risk guidelines. The RMC evaluates the actions initiated by Power Supply for consistency and compliance with the Policy. Idaho Power representatives meet with the CAG at least annually to assess effectiveness of the limits. Changes to the limits can be endorsed by the CAG and referred to the board of directors for approval.

Credit Risk

Idaho Power is subject to credit risk based on its activity with market counterparties. Idaho Power is exposed to this risk to the extent that a counterparty may fail to fulfill a contractual obligation to provide energy, purchase energy, or complete financial settlement for market activities. Idaho Power mitigates this exposure by actively establishing credit limits; measuring, monitoring, and reporting credit risk using appropriate contractual arrangements; and transferring of credit risk through the use of financial guarantees, cash or letters of credit. Idaho Power maintains a current list of acceptable counterparties and credit limits.

The use of performance assurance collateral in the form of cash, letters of credit, or guarantees is common industry practice. Idaho Power maintains margin agreements relating to its wholesale commodity contracts that allow performance assurance collateral to be requested of and/or posted with certain counterparties. As of December 31, 2011, Idaho Power had posted no performance assurance collateral. Should Idaho Power experience a reduction in its credit rating on Idaho Power's unsecured debt to below investment grade, Idaho Power could be subject to requests by its wholesale counterparties to post performance assurance collateral. Counterparties to derivative instruments and other forward contracts could request immediate payment or demand immediate ongoing full daily collateralization on derivative instruments and contracts in net liability positions. Based upon Idaho Power's current energy and fuel portfolio and market conditions as of December 31, 2011, the approximate amount of collateral that could be requested upon a downgrade to below investment grade is approximately $7 million. Idaho Power actively monitors the portfolio exposure and the potential exposure to additional requests for performance assurance collateral calls, through sensitivity analysis, to minimize capital requirements.

Idaho Power is obligated to provide service to all electric customers within its service area. Credit risk for Idaho Power's retail customers is managed by credit and collection policies that are governed by rules issued by the IPUC or OPUC. Idaho Power records a provision for uncollectible accounts, based upon historical experience, to provide for the potential loss from nonpayment by these customers. Idaho Power will continue to monitor the impact of the current economic conditions on nonpayment from customers and will make any necessary adjustments to its provision for uncollectible accounts.

Idaho utility customer relations rules prohibit Idaho Power from terminating electric service during the months of December through February to any residential customer who declares that he or she is unable to pay in full for utility service and whose household includes children, elderly, or infirm persons. Idaho Power's provision for uncollectible accounts could be affected by changes in future prices as well as changes in IPUC or OPUC regulations.

Equity Price Risk

IDACORP and Idaho Power are exposed to price fluctuations in equity markets, primarily through their defined benefit pension plan assets, a mine reclamation trust fund owned by an equity-method investment of Idaho Power, and other equity investments at Idaho Power. During 2011, the fair value of the defined benefit pension plan's assets decreased slightly; however, increases in the benefit liabilities were greater than the increases in the plan's assets, therefore resulting in an increase in future amounts required to be contributed to the plan. Based on current laws, Idaho Power estimates that the minimum contribution to the defined benefit pension plan in 2012 will be approximately $36 million. A hypothetical ten percent decrease in equity prices would result in an approximate $2.2 million decrease in the fair value of financial instruments that are classified as available-for-sale securities as of December 31, 2011.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Financial Statements and Financial Statement Schedules

IDACORP, Inc.
Consolidated Statements of Income

	Year Ended December 31,		
	2011	2010	2009
	(thousands of dollars except for per share amounts)		
Operating Revenues:			
Electric utility:			
General business	$ 834,545	$ 870,371	$ 883,765
Off-system sales	101,602	78,133	94,373
Other revenues	86,581	84,548	67,858
Total electric utility revenues	1,022,728	1,033,052	1,045,996
Other	4,028	2,977	3,804
Total operating revenues	1,026,756	1,036,029	1,049,800
Operating Expenses:			
Electric utility:			
Purchased power	163,336	143,769	167,198
Fuel expense	131,542	159,673	149,566
Power cost adjustment	38,497	51,226	66,710
Other operations and maintenance	338,640	293,925	292,813
Energy efficiency programs	37,663	44,184	31,821
Depreciation	119,789	115,921	110,626
Taxes other than income taxes	28,895	24,046	21,069
Total electric utility expenses	858,362	832,744	839,803
Other	4,146	4,615	6,414
Total operating expenses	862,508	837,359	846,217
Operating Income	164,248	198,670	203,583
Other Income, Net	21,209	15,165	16,997
Earnings (Losses) of Unconsolidated Equity-Method Investments	798	3,008	(1,033)
Interest Expense:			
Interest on long-term debt	79,349	80,490	73,371
Other interest, net of AFUDC	(7,823)	(5,376)	(561)
Total interest expense, net	71,526	75,114	72,810
Income Before Income Taxes	114,729	141,729	146,737
Income Tax (Benefit) Expense	(52,133)	(731)	22,362
Net Income	166,862	142,460	124,375
Adjustment for (income) loss attributable to noncontrolling interests	(169)	338	(25)
Net Income Attributable to IDACORP, Inc.	$ 166,693	$ 142,798	$ 124,350
Weighted Average Common Shares Outstanding - Basic (000’s)	49,457	48,193	47,124
Weighted Average Common Shares Outstanding - Diluted (000’s)	49,558	48,340	47,182
Earnings Per Share of Common Stock:			
Earnings Attributable to IDACORP, Inc. - Basic	$ 3.37	$ 2.96	$ 2.64
Earnings Attributable to IDACORP, Inc. - Diluted	$ 3.36	$ 2.95	$ 2.64
Dividends Declared Per Share of Common Stock	$ 1.20	$ 1.20	$ 1.20

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Statements of Comprehensive Income

	Year Ended December 31,		
	2011	**2010**	**2009**
	(thousands of dollars)		
Net Income	$ 166,862	$ 142,460	$ 124,375
Other Comprehensive Income:			
Net unrealized holding (losses) gains arising during the year, net of tax of ($257), $738, and $1,169	(400)	1,149	1,820
Unfunded pension liability adjustment, net of tax of ($1,062), ($1,573), and ($885)	(1,654)	(2,450)	(1,380)
Total Comprehensive Income	164,808	141,159	124,815
Comprehensive (income) loss attributable to noncontrolling interests	(169)	338	(25)
Comprehensive Income Attributable to IDACORP, Inc.	$ 164,639	$ 141,497	$ 124,790

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Balance Sheets

	December 31, 2011	December 31, 2010
	(thousands of dollars)	
Assets		
Current Assets:		
Cash and cash equivalents	$ 27,813	$ 228,677
Receivables:		
Customer (net of allowance of $1,239 and $1,499, respectively)	66,296	62,114
Other (net of allowance of $196 and $1,471, respectively)	8,197	10,157
Income taxes receivable	421	12,130
Accrued unbilled revenues	46,441	47,964
Materials and supplies (at average cost)	46,490	45,601
Fuel stock (at average cost)	47,865	27,547
Prepayments	12,405	11,063
Deferred income taxes	16,159	10,715
Current regulatory assets	34,279	6,216
Other	4,606	1,854
Total current assets	310,972	464,038
Investments	199,931	202,944
Property, Plant and Equipment:		
Utility plant in service	4,466,873	4,332,054
Accumulated provision for depreciation	(1,677,609)	(1,614,013)
Utility plant in service - net	2,789,264	2,718,041
Construction work in progress	591,475	416,950
Utility plant held for future use	6,974	7,076
Other property, net of accumulated depreciation	18,877	19,315
Property, plant and equipment - net	3,406,590	3,161,382
Other Assets:		
American Falls and Milner water rights	20,015	22,120
Company-owned life insurance	24,060	26,672
Regulatory assets	953,068	753,172
Long-term receivables (net of allowance of $2,743 and $1,861, respectively)	5,621	3,965
Other	40,352	41,762
Total other assets	1,043,116	847,691
Total	$ 4,960,609	$ 4,676,055

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Balance Sheets

	December 31, 2011	December 31, 2010
	(thousands of dollars)	
Liabilities and Equity		
Current Liabilities:		
Current maturities of long-term debt	$ 101,064	$ 122,572
Notes payable	54,200	66,900
Accounts payable	100,432	103,100
Income taxes accrued	505	—
Interest accrued	21,797	23,937
Uncertain tax positions	—	74,436
Current regulatory liabilities	29,738	8,011
Other	60,511	50,103
Total current liabilities	368,247	449,059
Other Liabilities:		
Deferred income taxes	772,047	566,473
Regulatory liabilities	332,057	298,094
Pension and other postretirement benefits	363,209	263,688
Other	75,805	74,470
Total other liabilities	1,543,118	1,202,725
Long-Term Debt	1,387,550	1,488,287
Commitments and Contingencies		
Equity:		
IDACORP, Inc. shareholders' equity:		
Common stock, no par value (shares authorized 120,000,000; 49,964,172 and 49,419,452 shares issued, respectively)	828,389	807,842
Retained earnings	840,916	733,879
Accumulated other comprehensive loss	(11,622)	(9,568)
Treasury stock (12,177 and 14,302 shares at cost, respectively)	(29)	(40)
Total IDACORP, Inc. shareholders' equity	1,657,654	1,532,113
Noncontrolling interests	4,040	3,871
Total equity	1,661,694	1,535,984
Total	$ 4,960,609	$ 4,676,055

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Statements of Cash Flows

	Year ended December 31,		
	2011	2010	2009
	(thousands of dollars)		
Operating Activities:			
Net income	$ 166,862	$ 142,460	$ 124,375
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	124,659	121,849	118,600
Deferred income taxes and investment tax credits	(52,913)	41,742	19,035
Changes in regulatory assets and liabilities	68,045	46,510	57,836
Pension and postretirement benefit plan expense	45,223	14,728	11,594
Contributions to pension and postretirement benefit plans	(22,088)	(65,601)	(7,569)
(Earnings) losses of unconsolidated equity-method investments	(798)	(3,008)	1,033
Distributions from unconsolidated equity-method investments	2,500	6,530	12,477
Allowance for equity funds used during construction	(25,484)	(16,551)	(7,555)
Other non-cash adjustments to net income, net	4,487	3,061	10,207
Change in:			
Accounts receivable and prepayments	(2,232)	14,243	(15,749)
Accounts payable and other accrued liabilities	5,428	4,014	(28,038)
Taxes accrued/receivable	15,113	(14,216)	28,535
Other current assets	(19,684)	3,848	(14,053)
Other current liabilities	2,171	13,682	(7,485)
Other assets	4,330	(3,662)	1,621
Other liabilities	(5,376)	(4,229)	(20,439)
Net cash provided by operating activities	310,243	305,400	284,425
Investing Activities:			
Additions to property, plant and equipment	(337,765)	(338,252)	(251,937)
Proceeds from the sale of utility assets	—	18,982	—
Proceeds from the sale of non-utility assets	—	—	2,250
Proceeds from the sale of emission allowances and RECs	6,314	6,408	2,382
Proceeds from sale of available-for-sale securities	—	—	9,006
Investments in affordable housing	(1,558)	(13,390)	(5,802)
Investments in unconsolidated affiliates	(2,645)	—	—
Purchase of available-for-sale securities	—	(7,000)	—
Maturity of held-to-maturity securities	—	—	425
Other	3,296	4,918	1,271
Net cash used in investing activities	(332,358)	(328,334)	(242,405)
Financing Activities:			
Issuance of long-term debt	—	200,000	230,000
Remarketing of pollution control bonds	—	—	166,100
Decrease in term loans	—	—	(170,000)
Retirement of long-term debt	(121,064)	(1,064)	(89,174)
Dividends on common stock	(59,668)	(57,872)	(56,820)
Net change in short-term borrowings	(12,700)	13,150	(93,600)
Issuance of common stock	17,501	48,644	24,328
Acquisition of treasury stock	(1,933)	(869)	(1,441)
Other	(885)	(3,365)	(7,254)
Net cash (used in) provided by financing activities	(178,749)	198,624	2,139
Net (decrease) increase in cash and cash equivalents	(200,864)	175,690	44,159
Cash and cash equivalents at beginning of the year	228,677	52,987	8,828
Cash and cash equivalents at end of the year	$ 27,813	$ 228,677	$ 52,987
Supplemental Disclosure of Cash Flow Information:			
Cash (received) paid during the year for:			
Income taxes	$ (12,405)	$ (27,112)	$ (21,401)
Interest (net of amount capitalized)	$ 70,969	$ 69,049	$ 67,039
Non-cash investing activities:			
Additions to property, plant and equipment in accounts payable	$ 26,331	$ 33,949	$ 19,075
Investments in affordable housing	$ —	$ 1,509	$ 8,276

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Statements of Equity

	Year ended December 31,		
	2011	2010	2009
	(thousands of dollars)		
Common Stock:			
Balance at beginning of year	$ 807,842	$ 756,475	$ 729,576
Issued	17,501	48,644	24,328
Other	3,046	2,723	2,571
Balance at end of year	828,389	807,842	756,475
Retained Earnings:			
Balance at beginning of year	733,879	649,180	581,605
Net income attributable to IDACORP, Inc.	166,693	142,798	124,350
Common stock dividends ($1.20 per share)	(59,656)	(58,099)	(56,775)
Balance at end of year	840,916	733,879	649,180
Accumulated Other Comprehensive (Loss) Income:			
Balance at beginning of year	(9,568)	(8,267)	(8,707)
Net unrealized holding (loss) gain on securities (net of tax)	(400)	1,149	1,820
Unfunded pension liability adjustment (net of tax)	(1,654)	(2,450)	(1,380)
Balance at end of year	(11,622)	(9,568)	(8,267)
Treasury Stock:			
Balance at beginning of year	(40)	(53)	(37)
Issued	1,944	882	1,425
Acquired	(1,933)	(869)	(1,441)
Balance at end of year	(29)	(40)	(53)
Total IDACORP, Inc. shareholders' equity at end of year	1,657,654	1,532,113	1,397,335
Noncontrolling Interests:			
Balance at beginning of year	3,871	4,209	4,434
Net income (loss) attributable to noncontrolling interests	169	(338)	25
Other	—	—	(250)
Balance at end of year	4,040	3,871	4,209
Total equity at end of year	$ 1,661,694	$ 1,535,984	$ 1,401,544

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Statements of Income

	Year Ended December 31,		
	2011	**2010**	**2009**
	(thousands of dollars)		
Operating Revenues:			
General business	$ 834,545	$ 870,371	$ 883,765
Off-system sales	101,602	78,133	94,373
Other revenues	86,581	84,548	67,858
Total operating revenues	1,022,728	1,033,052	1,045,996
Operating Expenses:			
Operation:			
Purchased power	163,336	143,769	167,198
Fuel expense	131,542	159,673	149,566
Power cost adjustment	38,497	51,226	66,710
Other operations and maintenance	338,640	293,925	292,813
Energy efficiency programs	37,663	44,184	31,821
Depreciation	119,789	115,921	110,626
Taxes other than income taxes	28,895	24,046	21,069
Total operating expenses	858,362	832,744	839,803
Income from Operations	164,366	200,308	206,193
Other Income (Expense):			
Allowance for equity funds used during construction	25,484	16,551	7,555
Earnings of unconsolidated equity-method investments	9,018	11,281	8,256
Other (expense) income, net	(4,462)	(2,868)	8,008
Total other income	30,040	24,964	23,819
Interest Charges:			
Interest on long-term debt	79,349	80,490	73,270
Other interest	5,039	4,110	4,060
Allowance for borrowed funds used during construction	(13,333)	(10,675)	(5,398)
Total interest charges	71,055	73,925	71,932
Income Before Income Taxes	123,351	151,347	158,080
Income Tax (Benefit) Expense	(41,399)	10,713	35,521
Net Income	$ 164,750	$ 140,634	$ 122,559

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Statements of Comprehensive Income

	Year Ended December 31,		
	2011	**2010**	**2009**
	(thousands of dollars)		
Net Income	$ 164,750	$ 140,634	$ 122,559
Other Comprehensive Income:			
Net unrealized holding (losses) gains arising during the year, net of tax of ($257), $738, and $1,169	(400)	1,149	1,820
Unfunded pension liability adjustment, net of tax of ($1,062), ($1,573), and ($885)	(1,654)	(2,450)	(1,380)
Total Comprehensive Income	$ 162,696	$ 139,333	$ 122,999

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Balance Sheets

	December 31, 2011	December 31, 2010
	(thousands of dollars)	
Assets		
Electric Plant:		
In service (at original cost)	$ 4,466,873	$ 4,332,054
Accumulated provision for depreciation	(1,677,609)	(1,614,013)
In service - net	2,789,264	2,718,041
Construction work in progress	591,475	416,950
Held for future use	6,974	7,076
Electric plant - net	3,387,713	3,142,067
Investments and Other Property	128,674	120,641
Current Assets:		
Cash and cash equivalents	19,316	224,233
Receivables:		
Customer (net of allowance of $1,239 and $1,499, respectively)	66,296	62,114
Other (net of allowance of $196 and $142, respectively)	8,011	8,835
Income taxes receivable	4,644	21,063
Accrued unbilled revenues	46,441	47,964
Materials and supplies (at average cost)	46,490	45,601
Fuel stock (at average cost)	47,865	27,547
Prepayments	12,274	10,910
Deferred income taxes	14,099	7,334
Current regulatory assets	34,279	6,216
Other	4,606	1,238
Total current assets	304,321	463,055
Deferred Debits:		
American Falls and Milner water rights	20,015	22,120
Company-owned life insurance	24,060	26,672
Regulatory assets	953,068	753,172
Other	38,988	40,666
Total deferred debits	1,036,131	842,630
Total	$ 4,856,839	$ 4,568,393

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Balance Sheets

	December 31,	
	2011	**2010**
	(thousands of dollars)	
Capitalization and Liabilities		
Capitalization:		
Common stock equity:		
Common stock, $2.50 par value (50,000,000 shares authorized; 39,150,812 shares outstanding)	$ 97,877	$ 97,877
Premium on capital stock	704,758	688,758
Capital stock expense	(2,097)	(2,097)
Retained earnings	735,304	630,259
Accumulated other comprehensive loss	(11,622)	(9,568)
Total common stock equity	1,524,220	1,405,229
Long-term debt	1,387,550	1,488,287
Total capitalization	2,911,770	2,893,516
Current Liabilities:		
Long-term debt due within one year	101,064	121,064
Accounts payable	99,716	102,474
Accounts payable to related parties	1,512	1,110
Interest accrued	21,797	23,930
Uncertain tax positions	—	74,436
Current regulatory liabilities	29,738	8,011
Other	59,785	48,733
Total current liabilities	313,612	379,758
Deferred Credits:		
Deferred income taxes	863,044	661,165
Regulatory liabilities	332,057	298,094
Pension and other postretirement benefits	363,209	263,688
Other	73,147	72,172
Total deferred credits	1,631,457	1,295,119
Commitments and Contingencies		
Total	$ 4,856,839	$ 4,568,393

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Statements of Capitalization

	December 31, 2011	December 31, 2010
	(thousands of dollars)	
Common Stock Equity:		
Common stock	$ 97,877	$ 97,877
Premium on capital stock	704,758	688,758
Capital stock expense	(2,097)	(2,097)
Retained earnings	735,304	630,259
Accumulated other comprehensive loss	(11,622)	(9,568)
Total common stock equity	1,524,220	1,405,229
Long-Term Debt:		
First mortgage bonds:		
6.60% Series due 2011	—	120,000
4.75% Series due 2012	100,000	100,000
4.25% Series due 2013	70,000	70,000
6.025% Series due 2018	120,000	120,000
6.15% Series due 2019	100,000	100,000
4.50 % Series due 2020	130,000	130,000
3.40% Series due 2020	100,000	100,000
6% Series due 2032	100,000	100,000
5.50% Series due 2033	70,000	70,000
5.50% Series due 2034	50,000	50,000
5.875% Series due 2034	55,000	55,000
5.30% Series due 2035	60,000	60,000
6.30% Series due 2037	140,000	140,000
6.25% Series due 2037	100,000	100,000
4.85% Series due 2040	100,000	100,000
Total first mortgage bonds	1,295,000	1,415,000
Amount due within one year	(100,000)	(120,000)
Net first mortgage bonds	1,195,000	1,295,000
Pollution control revenue bonds:		
5.15% Series due 2024	49,800	49,800
5.25% Series due 2026	116,300	116,300
Variable Rate Series 2000 due 2027	4,360	4,360
Total pollution control revenue bonds	170,460	170,460
American Falls bond guarantee	19,885	19,885
Milner Dam note guarantee	6,382	7,446
Note guarantee due within one year	(1,064)	(1,064)
Unamortized premium/discount - net	(3,113)	(3,440)
Total long-term debt	1,387,550	1,488,287
Total Capitalization	$ 2,911,770	$ 2,893,516

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Statements of Cash Flows

	Year ended December 31,		
	2011	2010	2009
	(thousands of dollars)		
Operating Activities:			
Net income	$ 164,750	$ 140,634	$ 122,559
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	124,028	121,219	117,878
Deferred income taxes and investment tax credits	(57,929)	78,631	15,082
Changes in regulatory assets and liabilities	68,045	46,509	57,836
Pension and postretirement benefit plan expense	45,223	14,728	11,594
Contributions to pension and postretirement benefit plans	(22,088)	(65,601)	(7,569)
Earnings of unconsolidated equity-method investments	(9,018)	(11,281)	(8,256)
Distributions from unconsolidated equity-method investments	—	4,755	10,720
Allowance for equity funds used during construction	(25,484)	(16,551)	(7,555)
Other non-cash adjustments to net income	1,159	(576)	5,649
Change in:			
Accounts receivables and prepayments	(2,468)	13,118	(14,828)
Accounts payable	5,357	4,080	(28,212)
Taxes accrued/receivable	19,217	(9,392)	38,003
Other current assets	(19,684)	3,848	(14,053)
Other current liabilities	2,169	13,674	(7,438)
Other assets	4,330	(3,662)	1,475
Other liabilities	(5,117)	(3,711)	(20,521)
Net cash provided by operating activities	292,490	330,422	272,364
Investing Activities:			
Additions to utility plant	(337,765)	(338,252)	(251,937)
Proceeds from the sale of utility assets	—	18,982	—
Proceeds from the sale of non-utility assets	—	—	2,250
Proceeds from the sale of emission allowances and RECs	6,314	6,408	2,382
Investments in unconsolidated affiliates	(2,645)	—	—
Purchase of available for sale securities	—	(7,000)	—
Other	2,665	4,366	1,171
Net cash used in investing activities	(331,431)	(315,496)	(246,134)
Financing Activities:			
Issuance of long-term debt	—	200,000	230,000
Retirement of long-term debt	(121,064)	(1,064)	(81,064)
Remarketing of pollution control revenue bonds	—	—	166,100
Decrease in term loans	—	—	(170,000)
Dividends on common stock	(59,705)	(58,070)	(56,911)
Net change in short term borrowings	—	—	(108,950)
Capital contribution from parent	16,000	50,000	20,000
Other	(1,207)	(3,184)	(6,921)
Net cash (used in) provided by financing activities	(165,976)	187,682	(7,746)
Net (decrease) increase in cash and cash equivalents	(204,917)	202,608	18,484
Cash and cash equivalents at beginning of the year	224,233	21,625	3,141
Cash and cash equivalents at end of the year	$ 19,316	$ 224,233	$ 21,625
Supplemental Disclosure of Cash Flow Information:			
Cash (received) paid during the year for:			
Income taxes	$ (759)	$ (57,378)	$ (13,756)
Interest (net of amount capitalized)	$ 70,491	$ 67,868	$ 66,231
Non-cash investing activities:			
Additions to property, plant and equipment in accounts payable	$ 26,331	$ 33,949	$ 19,075

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Statements of Retained Earnings

	Year Ended December 31,		
	2011	**2010**	**2009**
	(thousands of dollars)		
Retained Earnings, Beginning of Year	$ 630,259	$ 547,695	$ 482,047
Net Income	164,750	140,634	122,559
Dividends on Common Stock	(59,705)	(58,070)	(56,911)
Retained Earnings, End of Year	$ 735,304	$ 630,259	$ 547,695

The accompanying notes are an integral part of these statements.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

This Annual Report on Form 10-K is a combined report of IDACORP, Inc. (IDACORP) and Idaho Power Company (Idaho Power). Therefore, the Notes to the Consolidated Financial Statements apply to both IDACORP and Idaho Power. However, Idaho Power makes no representation as to the information relating to IDACORP's other operations.

Nature of Business

IDACORP is a holding company formed in 1998 whose principal operating subsidiary is Idaho Power. Idaho Power is an electric utility with a service territory covering approximately 24,000 square miles in southern Idaho and eastern Oregon. Idaho Power is regulated by the Federal Energy Regulatory Commission (FERC) and the state regulatory commissions of Idaho and Oregon. Idaho Power is the parent of Idaho Energy Resources Co. (IERCo), a joint venturer in Bridger Coal Company (BCC), which mines and supplies coal to the Jim Bridger generating plant owned in part by Idaho Power.

IDACORP's other subsidiaries include IDACORP Financial Services, Inc. (IFS), an investor in affordable housing and other real estate investments; Ida-West Energy Company (Ida-West), an operator of small hydroelectric generation projects that satisfy the requirements of the Public Utility Regulatory Policies Act of 1978 (PURPA); and IDACORP Energy (IE), a marketer of energy commodities, which wound down operations in 2003.

Principles of Consolidation

IDACORP's and Idaho Power's consolidated financial statements include the accounts of each company, the subsidiaries that the companies control, and any variable interest entities (VIEs) for which the companies are the primary beneficiaries. Intercompany balances have been eliminated in consolidation. Investments in subsidiaries that the companies do not control and investments in VIEs for which the companies are not the primary beneficiaries, but have the ability to exercise significant influence over operating and financial policies, are accounted for using the equity method of accounting.

The entities that IDACORP and Idaho Power consolidate consist primarily of the wholly-owned subsidiaries discussed above. In addition, IDACORP consolidates one VIE, Marysville Hydro Partners (Marysville), which is a joint venture owned 50 percent by Ida-West and 50 percent by Environmental Energy Company (EEC). At December 31, 2011, Marysville had approximately $20 million of assets, primarily a hydroelectric plant, and approximately $15 million of intercompany long-term debt, which is eliminated in consolidation. EEC has borrowed amounts from Ida-West to fund a portion of its required capital contributions to Marysville. The loans are payable from EEC's share of distributions and are secured by the stock of EEC and EEC's interest in Marysville. Ida-West is the primary beneficiary because the ownership of the intercompany note and the EEC note result in it controlling the entity. Creditors of Marysville have no recourse to the general credit of IDACORP and there are no other arrangements that could require IDACORP to provide financial support to Marysville or expose IDACORP to losses.

Through IERCo, Idaho Power holds a variable interest in BCC, a VIE for which it is not the primary beneficiary. IERCo is not the primary beneficiary because the power to direct the activities that most significantly impact the economic performance of BCC is shared with the joint venture partner. The carrying value of BCC was $102 million at December 31, 2011, and Idaho Power's maximum exposure to loss is the carrying value, any additional future contributions to BCC, and a $63 million guarantee for mine reclamation costs, which is discussed further in Note 9.

Through IFS, IDACORP also holds variable interests in VIEs for which it is not the primary beneficiary. These VIEs are affordable housing developments and other real estate investments in which IFS holds limited partnership interests ranging from 5 to 99 percent. As a limited partner, IFS does not control these entities and they are not consolidated. These investments were acquired between 1996 and 2010. IFS's maximum exposure to loss in these developments is limited to its net carrying value, which was $63 million at December 31, 2011.

Management Estimates

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

System of Accounts

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

Regulation of Utility Operations

IDACORP's and Idaho Power's financial statements reflect the effects of the different ratemaking principles followed by the jurisdictions regulating Idaho Power. The application of accounting principles related to regulated operations sometimes results in Idaho Power recording expenses and revenues in a different period than when an unregulated enterprise would. In these instances, the amounts are deferred as regulatory assets or regulatory liabilities on the balance sheet and recorded on the income statement when recovered or returned in rates. Additionally, regulators can impose regulatory liabilities upon a regulated company for amounts previously collected from customers and for amounts that are expected to be refunded to customers. The effects of applying these regulatory accounting principles to Idaho Power's operations are discussed in more detail in Note 3.

Cash and Cash Equivalents

Cash and cash equivalents include cash on hand and highly-liquid temporary investments that mature within 90 days of the date of acquisition.

Receivables and Allowance for Uncollectible Accounts

Customer receivables are recorded at the invoiced amounts and do not bear interest. A late payment fee of one percent may be assessed on account balances after 30 days. An allowance is recorded for potential uncollectible accounts. The allowance is reviewed periodically and adjusted based upon a combination of historical write-off experience, aging of accounts receivable, and an analysis of specific customer accounts. Adjustments are charged to income. Customer accounts receivable balances that remain outstanding after reasonable collection efforts are written off through a charge to the allowance and a credit to accounts receivable.

Other receivables, primarily notes receivable from business transactions, are also reviewed for impairment periodically, based upon transaction-specific facts. When it is probable that IDACORP or Idaho Power will be unable to collect all amounts due according to the contractual terms of the agreement, an allowance is established for the estimated uncollectible portion of the receivable and charged to income.

There were no impaired receivables without related allowances at December 31, 2011 and 2010. Once a receivable is determined to be impaired, any further interest income recognized is fully reserved.

Derivative Financial Instruments

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

Revenues

Operating revenues related to Idaho Power's sale of energy are recorded when service is rendered or energy is delivered to customers. Idaho Power accrues estimated unbilled revenues for electric services delivered to customers but not yet billed at year-end. Idaho Power collects franchise fees and similar taxes related to energy consumption. None of these collections are reported on the income statement. Beginning in February 2009, Idaho Power is collecting in base rates a portion of the allowance for funds used during construction (AFUDC) related to its Hells Canyon relicensing project. Cash collected under this ratemaking mechanism is not recorded as revenue, but is instead recorded as a regulatory liability.

Property, Plant and Equipment and Depreciation

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

All utility plant in service is depreciated using the straight-line method at rates approved by regulatory authorities. Annual depreciation provisions as a percent of average depreciable utility plant in service approximated 2.83 percent in 2011, 2.84 percent in 2010, and 2.81 percent in 2009.

Long-lived assets are periodically reviewed for impairment when events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If the sum of the undiscounted expected future cash flows from an asset is less than the carrying value of the asset, impairment must be recognized in the financial statements. There were no material impairments of these assets in 2011, 2010, or 2009.

Allowance for Funds Used During Construction

AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. With one exception, cash is not realized currently from such allowance; it is realized under the ratemaking process over the service life of the related property through increased revenues resulting from a higher rate base and higher depreciation expense. The component of AFUDC attributable to borrowed funds is included as a reduction to interest expense, while the equity component is included in other income. Idaho Power's weighted-average monthly AFUDC rates for 2011, 2010, and 2009 were 7.8 percent, 8.0 percent, and 6.7 percent, respectively. Idaho Power's reductions to interest expense for AFUDC were $13 million for 2011, $11 million for 2010, and $5 million for 2009. Other income included $25 million, $17 million, and $8 million of AFUDC for 2011, 2010, and 2009, respectively.

Income Taxes

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

Consistent with orders and directives of the Idaho Public Utilities Commission (IPUC), the regulatory authority having principal jurisdiction over Idaho Power's Idaho service territory, Idaho Power's deferred income taxes for plant-related items (commonly referred to as normalized accounting) are primarily provided for the difference between income tax depreciation and book depreciation used for financial statement purposes. Unless contrary to applicable income tax guidance, deferred income taxes are not provided for those income tax timing differences where the prescribed regulatory accounting methods direct Idaho Power to recognize the tax impact currently for rate making and financial reporting. Regulated enterprises are required to recognize such adjustments as regulatory assets or liabilities if it is probable that such amounts will be recovered from or returned to customers in future rates.

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

Income taxes are discussed in more detail in Note 2.

Comprehensive Income

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

	2011	2010
	(thousands of dollars)	
Unrealized holding gains on available-for-sale securities	$ 2,569	$ 2,969
Senior Management Security Plan	(14,191)	(12,537)
Total	$ (11,622)	$ (9,568)

Other Accounting Policies

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

Reclassifications

Certain prior year amounts have been reclassified to conform to the current year presentation. Net income, cash flows, and shareholders' equity were not affected by these reclassifications.

- Certain amounts related to regulatory assets and liabilities that were included in noncurrent regulatory assets and liabilities were reclassified as current regulatory assets and liabilities in the consolidated balance sheets.
- Pension and other postretirement benefits of $264 million were reclassified from other noncurrent liabilities to a separate line in the consolidated balance sheets.

New Accounting Pronouncements

The Financial Accounting Standards Board (FASB) has issued the following accounting guidance, which is effective for years beginning after December 15, 2011:

- In May 2011, the FASB issued guidance to provide a consistent definition of fair value and ensure that the fair value measurement and disclosure requirements are similar between generally accepted accounting principles in the United States and International Financial Reporting Standards. The guidance changes certain fair value measurement principles and enhances the disclosure requirements, particularly for Level 3 fair value measurements. IDACORP and Idaho Power are currently assessing the impact of the guidance but do not believe that the adoption of this guidance will have a material effect on their consolidated financial statements.

2. INCOME TAXES

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

	IDACORP			Idaho Power		
	2011	2010	2009	2011	2010	2009
	(thousands of dollars)					
Federal income tax expense at 35% statutory rate	$ 40,096	$ 49,723	$ 51,349	$ 43,173	$ 52,972	$ 55,328
Change in taxes resulting from:						
AFUDC	(13,586)	(9,529)	(4,533)	(13,586)	(9,529)	(4,533)
Capitalized interest	6,465	3,674	1,529	6,465	3,674	1,529
Investment tax credits	(3,355)	(3,378)	(3,404)	(3,355)	(3,378)	(3,404)
Repair allowance	—	—	(3,500)	—	—	(3,500)
Removal costs	(2,244)	(2,850)	(3,810)	(2,244)	(2,850)	(3,810)
Capitalized overhead costs	(5,950)	(3,500)	(3,500)	(5,950)	(3,500)	(3,500)
Capitalized repair costs	(14,000)	(10,500)	—	(14,000)	(10,500)	—
Tax method change – uniform capitalization	—	(65,333)	—	—	(65,333)	—
Tax method change – capitalized repairs	—	(44,466)	—	—	(44,466)	—
Uncertain tax positions – established	—	74,436	1,138	—	74,436	1,138
Uncertain tax positions – settled	(63,138)	(1,138)	(4,119)	(63,138)	(1,138)	(4,119)
State income taxes, net of federal benefit	1,375	4,565	1,216	1,846	5,074	1,903
Depreciation	14,100	13,138	3,895	14,100	13,138	3,895
Affordable housing tax credits	(6,438)	(7,309)	(7,870)	—	—	—
Other, net	(5,458)	1,736	(6,029)	(4,710)	2,113	(5,406)
Total income tax (benefit) expense	$ (52,133)	$ (731)	$ 22,362	$ (41,399)	$ 10,713	$ 35,521
Effective tax rate	(45.5)%	(0.5)%	15.2%	(33.6)%	7.1%	22.5%

The items comprising income tax (benefit) expense are as follows:

	IDACORP			Idaho Power		
	2011	2010	2009	2011	2010	2009
	(thousands of dollars)					
Income taxes currently payable:						
Federal	$ (10)	$ (39,518)	$ 6,199	$ 9,234	$ (62,338)	$ 21,035
State	790	(5,960)	108	7,296	(5,580)	2,385
Total	780	(45,478)	6,307	16,530	(67,918)	23,420
Income taxes deferred:						
Federal	23,940	(22,582)	23,309	24,559	10,902	20,638
State	(1,285)	(4,436)	(4,509)	(6,920)	(4,036)	(5,792)
Total	22,655	(27,018)	18,800	17,639	6,866	14,846
Uncertain tax positions:						
Federal	(66,225)	65,222	(2,496)	(66,225)	65,222	(2,496)
State	(8,211)	8,076	(485)	(8,211)	8,076	(485)
Total	(74,436)	73,298	(2,981)	(74,436)	73,298	(2,981)
Investment tax credits:						
Deferred	2,223	1,845	3,640	2,223	1,845	3,640
Restored	(3,355)	(3,378)	(3,404)	(3,355)	(3,378)	(3,404)
Total	(1,132)	(1,533)	236	(1,132)	(1,533)	236
Total income tax (benefit) expense	$ (52,133)	$ (731)	$ 22,362	$ (41,399)	$ 10,713	$ 35,521

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

	IDACORP		Idaho Power	
	2011	2010	2011	2010
	(thousands of dollars)			
Deferred tax assets:				
Regulatory liabilities	$ 45,473	$ 46,199	$ 45,473	$ 46,199
Advances for construction	5,118	7,061	5,118	7,061
Deferred compensation	22,172	21,299	22,067	21,045
Advanced payments	12,958	8,292	12,958	8,292
Power cost adjustments	1,711	—	1,711	—
Tax credits	119,310	120,229	8,571	6,471
Revenue sharing	10,594	—	10,594	—
Retirement benefits	122,445	88,827	122,445	88,827
Other	5,380	8,617	3,758	4,422
Total	345,161	300,524	232,695	182,317
Deferred tax liabilities:				
Property, plant and equipment	333,335	284,794	333,335	284,794
Regulatory assets	599,992	422,216	599,992	422,216
Conservation programs	3,464	7,611	3,464	7,611
Power cost adjustments	—	11,833	—	11,833
Partnership investments	19,749	18,380	6,181	4,551
Retirement benefits	122,712	93,997	122,712	93,997
Other	21,797	17,451	15,956	11,146
Total	1,101,049	856,282	1,081,640	836,148
Net deferred tax liabilities	$ 755,888	$ 555,758	$ 848,945	$ 653,831

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

Tax Credits Carryforwards

As of December 31, 2011, IDACORP had $94.1 million of general business credit carryforward for federal income tax purposes and $25.2 million of Idaho investment tax credit carryforward. The general business credit carryforward period expires from 2024 to 2031, and the Idaho investment tax credit expires from 2019 to 2025.

Uncertain Tax Positions

A reconciliation of the beginning and ending amount of unrecognized tax benefits for IDACORP and Idaho Power is as follows (in thousands of dollars):

	2011	2010	2009
Balance at January 1,	$ 74,436	$ 1,138	$ 4,119
Additions for tax positions of the current year	—	2,822	—
Additions for tax positions of prior years	—	71,614	1,138
Reductions for tax positions of prior years	(66,379)	(1,138)	(4,119)
Settlements with taxing authorities	(8,057)	—	—
Balance at December 31,	$ —	$ 74,436	$ 1,138

IDACORP and Idaho Power recognize interest accrued related to unrecognized tax benefits as interest expense and penalties as other expense. Both companies recognized a net reduction in interest expense of $0.2 million in 2011, interest expense of $0.2 million in 2010, and a net reduction in interest expense of $0.2 million in 2009. Accrued interest at both companies was zero as of December 31, 2011, $0.2 million as of December 31, 2010, and zero as of December 31, 2009. No penalties are accrued.

IDACORP and Idaho Power are subject to examination by their major tax jurisdictions - U.S. federal and the State of Idaho. The open tax years are 2011 for federal and 2008-2011 for Idaho. In May 2009, IDACORP formally entered the U.S. Internal Revenue Service (IRS) Compliance Assurance Process (CAP) program for its 2009 tax year and has remained in the CAP program for all subsequent years. The CAP program provides for IRS examination and issue resolution throughout the current year with the objective of return filings containing no contested items.

With the resolution of Idaho Power's capitalized repairs and uniform capitalization tax accounting methods examinations (discussed below), the 2009 tax year is now closed for federal purposes. In 2011, the IRS also completed its examination of IDACORP's 2010 tax year with no unresolved income tax issues. IDACORP and Idaho Power believe there are no remaining material tax uncertainties for 2011 and prior tax years.

Tax Accounting Method Change for Repair-Related Expenditures

In June 2010, Idaho Power completed its evaluation of a tax accounting method change for its 2009 tax year that allows a current income tax deduction for repair-related expenditures on its utility assets that are currently capitalized for financial reporting and tax purposes. In September 2010, Idaho Power adopted this method following the automatic consent procedures with the filing of IDACORP's 2009 consolidated federal income tax return. The method was subject to audit under IDACORP's 2009 CAP examination.

For the year ended December 31, 2010, Idaho Power recorded a $44.5 million tax benefit related to the filed deduction for the cumulative method change adjustment and an additional $11.7 million tax benefit for the annual deduction estimate included in its 2010 income tax provision. As of December 31, 2010, Idaho Power had a current uncertain tax position liability of $14.7 million related to this method.

In April 2011, IDACORP and the IRS reached an agreement on Idaho Power's tax accounting method change for capitalized repairs. Accordingly, the IRS finalized the 2009 CAP examination and submitted its report on the 2009 tax year to the U.S. Congress Joint Committee on Taxation (Joint Committee) for review. Idaho Power considers the capitalized repairs method effectively settled and believes that no material income tax uncertainties remain for the method. As such, Idaho Power recognized $3.4 million of its previously unrecognized tax benefits for this method in 2011.

For the year ended December 31, 2011, the capitalized repairs annual tax deduction estimate included in Idaho Power's income tax provision produced a $15.6 million tax benefit. The amount of this annual tax deduction will vary depending on a number of factors, but most directly by the amount and type of Idaho Power's annual capital additions. The reversal of this temporary difference from prior years will offset a portion of the ongoing annual benefit.

Idaho Power's prescribed regulatory accounting treatment requires immediate income recognition for temporary tax differences of this type. A regulatory asset is established to reflect Idaho Power's ability to recover increased income tax expense when such temporary differences reverse.

Tax Accounting Method Change for Uniform Capitalization

In September 2009, the IRS issued Industry Director Directive #5 (IDD), which discusses the IRS's compliance priorities and audit techniques related to the allocation of mixed service costs in the uniform capitalization methods of electric utilities. Within IDACORP's 2009 CAP examination, the IRS and Idaho Power worked through the impact the IDD guidance had on Idaho Power's uniform capitalization method and reached agreement during 2010. The agreement provided that Idaho Power change its uniform capitalization method to the agreed upon method under the IDD with the filing of IDACORP's 2009 consolidated federal income tax return. While Idaho Power had an agreement with the IRS for examination and return filing purposes, the agreement required Joint Committee approval to be final.

The resulting tax deductions available under the agreed upon uniform capitalization method were significantly greater than Idaho Power's prior method. For the year ended December 31, 2010, Idaho Power recorded a tax benefit of $65.3 million related to the cumulative method change adjustment (tax years 1986 through 2009) for this method and $5.6 million of tax expense from the reversal of this temporary difference. As of December 31, 2010, Idaho Power had a current uncertain tax position liability equal to the $59.7 million net tax benefit recorded for the method change. Due to the method change agreement with the IRS, Idaho Power reversed the uncertain tax position liability for its 2009 uniform capitalization deduction, resulting in a $1.1 million tax benefit for the year ended December 31, 2010.

In September 2011, the IRS notified IDACORP that the Joint Committee had completed its review of IDACORP's 2009 tax year and approved the uniform capitalization method agreement. Idaho Power considers the uniform capitalization method effectively settled and believes that no material income tax uncertainties remain for the method. Accordingly, Idaho Power recognized $56.9 million of its previously unrecognized tax benefits for tax years 2009 and prior in 2011.

For the year ended December 31, 2011, the uniform capitalization annual tax deduction estimate included in Idaho Power's income tax provision produced a $6.6 million tax benefit. The amount of this annual tax deduction will vary depending on a number of factors, but most directly by the amount and type of Idaho Power's annual capital additions. The reversal of this temporary difference from prior years will offset a portion of the ongoing annual benefit. The prescribed regulatory accounting treatment for this method is the same as discussed earlier for the capitalized repairs method.

Cash Impacts of Tax Method Changes

In 2011, IDACORP and Idaho Power paid previously accrued income tax liabilities of $3.9 million and $8.1 million, respectively, related to the capitalized repairs examination agreement. The difference in liabilities is primarily due to IDACORP's utilization of deferred federal general business tax credits. There were no 2011 cash impacts related to the uniform capitalization method settlement as income tax refunds for the method change were received in 2010.

In 2010, IDACORP and Idaho Power realized federal and state cash benefits associated with the 2009 capitalized repairs and uniform capitalization method changes of $33 million and $42 million, respectively. The majority of this cash benefit was realized through reductions to cash payments that would have otherwise been owed to taxing authorities for the 2009 tax year and a federal refund of $24 million received in 2010. Additionally, approximately $6 million of state cash benefits were realized through reduced tax payments for the 2010 year.

The capitalized repairs and uniform capitalization method changes produced an income statement tax benefit of $44.5 million and $65.3 million, respectively, in 2010 prior to the accrual for uncertain tax positions. A portion of this earnings benefit related to previously deferred income tax expense being flowed through the income statement, which does not deliver any cash benefits. In addition, federal tax credits of $17 million previously recognized were restored due to the reduction of 2009 taxable income by the two method changes. The restored credits were a reduction to cash received in 2010, but will be available to deliver cash benefits in future periods.

3. REGULATORY MATTERS

Regulatory Assets and Liabilities

Regulatory assets represent incurred costs that have been deferred because it is probable they will be recovered through future rates collected from customers. Regulatory liabilities represent obligations to make refunds to customers for previous collections, except for cost of removal (which represents the cost of removing future electric assets). The following table presents a summary of Idaho Power's regulatory assets and liabilities (in thousands of dollars):

Description	Remaining Amortization Period	Earning a Return[1]	Not Earning a Return	Total as of December 31, 2011	Total as of December 31, 2010
Regulatory Assets:					
Income taxes		$ —	$ 603,772	$ 603,772	$ 429,457
Unfunded postretirement benefits[2]		—	262,503	262,503	182,742
Pension expense deferrals[3]	2012-2015	38,976	19,068	58,044	63,833
Energy efficiency program costs[3]		15,956	—	15,956	19,467
Power supply costs[3]	Varies	8,490	—	8,490	29,753
Fixed cost adjustment[3]	Varies	14,457	—	14,457	12,340
Asset retirement obligations[4]		—	15,557	15,557	15,372
Mark-to-market liabilities[5]		—	4,707	4,707	2,278
Other	2012-2021	993	2,868	3,861	3,573
Total		$ 78,872	$ 908,475	$ 987,347	$ 758,815
Regulatory Liabilities:					
Income taxes		$ —	$ 49,253	$ 49,253	$ 53,440
Removal costs[4]		—	163,173	163,173	157,642
Investment tax credits		—	70,841	70,841	71,972
Deferred revenue-AFUDC [3]		21,034	12,111	33,145	21,211
Power supply costs [3]	Varies	13,121	—	13,121	—
2010 Settlement agreement sharing mechanism[3]	2013	27,099	—	27,099	—
Mark-to-market assets[5]		—	3,754	3,754	573
Other	2012	1,250	159	1,409	1,267
Total		$ 62,504	$ 299,291	$ 361,795	$ 306,105

(1) Earning a return includes either interest or a return on the investment as a component of rate base at the allowed rate of return.
(2) Represents the unfunded obligation of Idaho Power's pension and postretirement benefit plans, which are discussed in Note 11.
(3) These items are discussed in more detail below.
(4) Asset retirement obligations and removal costs are discussed in Note 13.
(5) Mark-to-market assets and liabilities are discussed in Note 16.

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

Power Cost Adjustment Mechanisms and Deferred Power Supply Costs

In both its Idaho and Oregon jurisdictions, Idaho Power's power cost adjustment (PCA) mechanisms address the volatility of power supply costs and provide for annual adjustments to the rates charged to its retail customers. The PCA mechanisms compare Idaho Power's actual and forecast net power supply costs (primarily fuel and purchased power less off-system sales) against net power supply costs currently being recovered in retail rates.

Under the PCA mechanisms, certain differences between actual net power supply costs incurred by Idaho Power and the costs included in retail rates are recorded as a deferred charge or credit on the balance sheets for future recovery or refund through retail rates. The power supply costs deferred primarily result from changes in wholesale market prices and transaction volumes, changes in contracted power purchase prices and volumes, and the levels of hydroelectric and thermal generation.

Idaho Jurisdiction Power Cost Adjustment Mechanism: In the Idaho jurisdiction, the annual PCA adjustments are based on (a) a forecast component, based on a forecast of net power supply costs in the coming year as compared to net power supply costs in base rates; and (b) a true-up component, based on the difference between the previous year's actual net power supply costs and the previous year's forecast. The latter component also includes a balancing mechanism so that, over time, the actual collection or refund of authorized true-up dollars matches the amounts authorized. The Idaho PCA mechanism also includes:

- a cost or benefit sharing ratio that allocates the deviations in net power supply expenses between customers (95 percent) and shareholders (5 percent), with the exception of expenses associated with PURPA power purchases, which are allocated 100 percent to customers;
- a load change adjustment rate (LCAR), which is intended to eliminate recovery of power supply expenses already collected in rates associated with load changes resulting from changing weather conditions, a growing customer base, or changing customer use patterns; and
- third-party transmission expenses (paid to third parties to facilitate wholesale purchases and sales of energy) as a component of net power supply costs for purposes of calculating the PCA.

The table below summarizes Idaho PCA rate adjustments during each of the years ended December 31, 2011, 2010, and 2009.

Effective Date	**$ Change (millions)**		**Notes**
June 1, 2011	$	(40.4)	The reduction to Idaho PCA rates was net of $10.0 million of Idaho Power's energy efficiency rider deferral balance that the IPUC authorized for recovery in Idaho Power's Idaho PCA rates.
June 1, 2010	$	(146.9)	The IPUC's order was made in conjunction with a January 2010 rate settlement agreement described below in "January 2010 and December 2011 Idaho Settlement Agreements." Concurrent with the PCA rate decrease, the IPUC authorized an $88.7 million increase in base rates, $63.7 million of which was related to power supply costs.
June 1, 2009	$	84.3	

Oregon Jurisdiction Power Cost Adjustment Mechanism: Idaho Power's power cost recovery mechanism in Oregon has two components: an annual power cost update (APCU) and a power cost adjustment mechanism (PCAM). The APCU allows Idaho Power to reestablish its Oregon base net power supply costs annually, separate from a general rate case, and to forecast net power supply costs for the upcoming water year. The PCAM is a true-up filed annually in February. The filing calculates the deviation between actual net power supply expenses incurred for the preceding calendar year and the net power supply expenses recovered through the APCU for the same period. Under the PCAM, Idaho Power is subject to a portion of the business risk or benefit associated with this deviation through application of an asymmetrical deadband (or range of deviations) within which Idaho Power absorbs cost increases or decreases. For deviations in actual power supply costs outside of the deadband, the PCAM provides for 90/10 sharing of costs and benefits between customers and Idaho Power. However, collection by Idaho Power will occur only to the extent that Idaho Power's actual return on equity (ROE) for the year is no greater than 100 basis points below Idaho Power's last authorized ROE. A refund to customers will occur only to the extent that Idaho Power's actual ROE for that year is no less than 100 basis points above Idaho Power's last authorized ROE.

Oregon jurisdiction power supply cost changes under the APCU and PCAM during each of the three years ended December 31, 2011, 2010, and 2009 were as follows:

Year and Mechanism	**APCU or PCAM Adjustment**
2011 PCAM	Actual net power supply costs were below the deadband, resulting in a $1.5 million deferral.
2011 APCU	A rate decrease of $2.2 million annually took effect June 1, 2011.
2010 PCAM	Actual net power supply costs were within the deadband, resulting in no deferral.
2010 APCU	A rate increase of $2.6 million annually took effect June 1, 2010.
2009 PCAM	Actual net power supply costs were within the deadband, resulting in no deferral.
2009 APCU	A rate increase of $3.9 million annually took effect June 1, 2009.

In May 2009, the OPUC adopted a stipulation allowing Idaho Power to defer excess net power supply costs of $6.4 million (including interest through the date of the order) for the period May 1 through December 31, 2007. Idaho Power recorded the $6.4 million deferral in 2009 as a reduction to PCA expense. The amount to be recovered was reduced by $0.9 million of previously deferred SO_2 emission allowance sales (including interest) during the same period. Effective January 2011, these costs are being collected through rates and amortized.

Idaho Regulatory Matters

2011 Idaho General Rate Case and Settlement: On June 1, 2011, Idaho Power filed a general rate case and proposed rate schedules with the IPUC, Case No. IPC-E-11-08. The filing was based on a 2011 test year and requested approximately $82.6 million in additional Idaho jurisdiction annual revenues in base rates, a 9.9 percent overall average rate increase for Idaho customers.

On September 23, 2011, Idaho Power, the IPUC Staff, and other interested parties publicly filed a settlement stipulation with the IPUC resolving most of the key contested issues in the Idaho general rate case. On December 30, 2011, the IPUC issued an order approving the settlement stipulation. The settlement stipulation approved by the December 30, 2011 order provides for a 7.86 percent authorized rate of return on an Idaho-jurisdictional rate base of approximately $2.36 billion. The approved settlement stipulation resulted in a 4.07 percent, or $34.0 million, overall increase in Idaho Power's annual Idaho jurisdictional base rate revenues, effective January 1, 2012. Neither the order nor the settlement stipulation specified an authorized rate of return on equity.

The settlement stipulation approved by the order also addressed Idaho Power's calculation of the LCAR to be applied in Idaho Power's PCA mechanism. The LCAR adjusts power supply cost recovery within the Idaho PCA formula upwards or downwards for differences between actual load and the load used in calculating base rates. The settlement stipulation provides for a LCAR of $18.16 per megawatt-hour, effective January 1, 2012, compared to the rate of $19.67 per megawatt-hour in effect prior to that date.

In its general rate case application, Idaho Power had requested approval of the current fixed cost adjustment (FCA) mechanism pilot program, described below, as a permanent rate mechanism for residential and small commercial class customers. Neither the December 30, 2011 order nor the settlement stipulation resolves whether the fixed cost adjustment pilot program should be made permanent.

Neither the order nor the settlement stipulation imposes a moratorium on Idaho Power's filing a general revenue requirement case at a future date.

January 2010 and December 2011 Idaho Settlement Agreements: On January 13, 2010, the IPUC approved a settlement agreement among Idaho Power, several of Idaho Power’s customers, the IPUC Staff, and others. Significant elements of the settlement agreement included:

- a specified distribution of the reduction in 2010 PCA that would reduce customer rates, provide up to a $25 million general increase in annual base rates, and reset base power supply costs for the PCA, effective with the June 1, 2010 PCA rate change. This provision anticipated a significant reduction in PCA rates for the 2010-2011 PCA year;
- a provision to share with Idaho customers 50 percent of any Idaho-jurisdiction earnings in excess of a 10.5 percent return on equity in any calendar year from 2009 to 2011; and
- a provision to allow the additional amortization of accumulated deferred investment tax credits (ADITC) if Idaho Power's Idaho-jurisdiction rate of return on year-end equity (Idaho ROE) is below 9.5 percent in any calendar year from 2009 to 2011. Idaho Power was permitted to amortize additional ADITC in an amount up to $45 million over the three-year period, but could use no more than $15 million in any one year unless there is a carryover. Carryover amounts were added to the $15 million annual allowance up to a maximum amortization of $25 million in any one year.

On April 15, 2010, Idaho Power filed its annual application with the IPUC to implement new PCA rates to be effective June 1, 2010 through May 31, 2011, and to change base rates, pursuant to the terms of the January 2010 Idaho settlement agreement. On May 28, 2010, the IPUC issued its order approving a $146.9 million decrease in the PCA, along with a base rate increase of $88.7 million. The net effect of these two rate adjustments was an overall decrease in customer rates of $58.2 million, effective June 1, 2010. The $88.7 million base rate increase reflects a $63.7 million increase in base power supply costs and a $25 million increase in base rates.

Because Idaho Power's actual Idaho ROE was between 9.5 and 10.5 percent in 2009 and 2010, the sharing and amortization provisions of the January 2010 settlement agreement were not triggered. However, recognition of income tax benefits in 2011 had a significant impact on Idaho Power's actual Idaho ROE and contributed to the triggering of the sharing mechanism for 2011. In accordance with the terms of the settlement agreement, Idaho Power recorded a $27.1 million reduction in revenue and regulatory liability in 2011, reflecting 50 percent of Idaho Power's 2011 Idaho-jurisdictional earnings above a 10.5 percent Idaho ROE to be shared with Idaho customers.

The sharing and ADITC amortization provisions of the January 2010 settlement agreement terminated on December 31, 2011. On December 27, 2011, the IPUC issued an order, separate from the general rate case proceeding, approving a settlement stipulation that had been executed by Idaho Power, the IPUC Staff, and one large industrial customer of Idaho Power and filed with the IPUC on December 12, 2011. The settlement stipulation provides that:

- if Idaho Power's actual Idaho ROE for 2012, 2013, or 2014 is less than 9.5 percent, then Idaho Power may amortize additional ADITC to help achieve a minimum 9.5 percent Idaho ROE in the applicable year. Idaho Power would be permitted to amortize additional ADITC in an aggregate amount up to $45 million over the three-year period, but could use no more that $25 million in 2012;
- if Idaho Power's actual Idaho ROE for 2012, 2013, or 2014 exceeds 10.0 percent, the amount of Idaho Power's Idaho jurisdictional earnings exceeding a 10.0 percent, but less than a 10.5 percent, Idaho ROE for the applicable year would be shared equally between Idaho Power and its Idaho customers; and
- if Idaho Power's actual Idaho ROE for 2012, 2013, or 2014 exceeds 10.5 percent, the amount of Idaho Power's Idaho jurisdictional earnings exceeding a 10.5 percent Idaho ROE for the applicable year would be allocated 75 percent to Idaho Power's Idaho customers and 25 percent to Idaho Power.

The settlement stipulation provides that the return on year-end equity thresholds (9.5 percent, 10.0 percent, and 10.5 percent) will be automatically adjusted prospectively in the event the IPUC approves a change to Idaho Power's authorized return on equity as part of a general rate case proceeding seeking a rate change effective prior to January 1, 2015. The automatic adjustments would be as follows: (a) the 9.5 percent return on year-end equity trigger in the settlement stipulation would be replaced by the percentage equal to 95 percent of the new authorized return on equity, (b) the 10.0 percent return on year-end equity trigger in the settlement stipulation would be re-established at the new authorized return on equity amount, and (c) the 10.5 percent return on year-end equity trigger in the settlement stipulation would be replaced by the percentage equal to 105 percent of the new authorized return on equity.

In consideration of these terms, the settlement stipulation provided that Idaho Power would also allocate to customers 75 percent of Idaho Power's own share of 2011 Idaho jurisdictional earnings over a 10.5 percent Idaho ROE. As a result, Idaho Power recorded in 2011 a $20.3 million pre-tax charge to pension expense and an associated decrease in deferred pension regulatory asset, representing the additional amount to be allocated to Idaho customers.

2008 Idaho General Rate Case: On January 30, 2009, the IPUC issued an order approving an increase in Idaho base rates, effective February 1, 2009, of approximately $20.9 million annually, a return on equity of 10.5 percent, and an overall rate of return of 8.18 percent. On February 19, 2009, Idaho Power filed a request for reconsideration with the IPUC and on March 19, 2009, the IPUC issued an order that increased Idaho Power's Idaho base rates by an additional $6.1 million to approximately $27 million for this rate case. The January 30, 2009 order authorized approximately $15 million related to increases in base net power supply costs. It also allowed Idaho Power to include in Idaho-jurisdictional rates approximately $6.5 million ($10.7 million including income tax gross-up) of 2009 AFUDC relating to the Hells Canyon Complex relicensing project. Typically, AFUDC is not included in rates until a project is in use and benefiting customers, but the IPUC determined that including this amount in current rates is in the public interest. Because AFUDC is already recorded on an accrual basis, this portion of the rate increase improves cash flows but does not have a current impact on Idaho Power's net income. The amounts collected are being deferred as a regulatory liability and will be recognized in revenues over the life of the new license once it has been issued.

Idaho Fixed Cost Adjustment : The FCA began as a pilot program for Idaho Power's Idaho residential and small general service customers, running from 2007 through 2009. The FCA is designed to remove Idaho Power's disincentive to invest in energy efficiency programs by separating (or decoupling) the recovery of fixed costs from the variable kilowatt-hour charge and linking it instead to a set amount per customer. On April 29, 2010, the IPUC approved a two-year extension of the FCA pilot program, effective retroactive to January 1, 2010, through December 31, 2011. On October 19, 2011, Idaho Power filed an application with the IPUC requesting that the FCA pilot program become permanent for residential and small general service customer classes effective January 1, 2012; a determination from the IPUC is pending.

The following table summarizes FCA rate adjustments since inception:

FCA Year	Period rates in effect	Annual Amount (in millions)
2010	June 1, 2011-May 31, 2012	9.3
2009	June 1, 2010-May 31, 2011	6.3
2008	June 1, 2009-May 31, 2010	2.7
2007	June 1, 2008-May 31, 2009	(2.4)

As of December 31, 2011, the deferral balance for the FCA was $14.5 million.

Defined Benefit Pension Plan Contribution Recovery: Idaho Power defers its Idaho-jurisdiction pension expense as a regulatory asset until recovered from Idaho customers. As of December 31, 2011, Idaho Power's deferral balance was $58.0 million. Deferred pension costs are expected to be amortized to expense to match the revenues received when contributions are recovered through rates. Idaho Power only records a carrying charge on the unrecovered balance of cash contributions.

In May 2010, the IPUC approved Idaho Power’s request to increase rates to allow recovery of Idaho Power’s 2009 cash contribution to its defined benefit pension plan, which contribution was made in September 2010. Idaho Power’s application sought approval of $5.4 million in pension cost recovery over a one-year period to allow recovery contemporaneous with Idaho Power’s expected cash contributions to the plan.

In September 2010, Idaho Power elected to make a $60 million contribution to its defined benefit pension plan, rather than the minimum required funding amount, to bring the defined benefit pension plan to a more funded position, potentially reducing future required contributions and Pension Benefit Guaranty Corporation premiums. On October 1, 2010, Idaho Power filed an application with the IPUC requesting an order accepting Idaho Power's 2011 retirement benefits package, but not requesting recovery through rates of additional pension plan contributions. On April 28, 2011, the IPUC issued an order accepting Idaho Power's 2011 retirement benefits package.

On March 15, 2011, Idaho Power filed an application with the IPUC requesting an increase in the amount included in base rates for recovery of the Idaho-allocated portion of Idaho Power's cash contributions to its defined benefit pension plan from the then-current amount of $5.4 million to approximately $17.1 million annually. On May 19, 2011, the IPUC approved Idaho Power’s application, with new rates effective on June 1, 2011. In September 2011, Idaho Power contributed an additional $18.5 million to its defined benefit pension plan.

Transmission Revenue Shortfall Filing: On January 15, 2009, the FERC issued an order that required Idaho Power to reduce its transmission service rates to FERC jurisdictional customers and refund to transmission customers transmission revenues that Idaho Power had received starting in 2006. This refund ultimately resulted in under-recovery of transmission costs by Idaho Power, and in October 2009 the IPUC authorized Idaho Power to record an Idaho-jurisdiction regulatory asset for the transmission revenue shortfall, for future recovery in customer rates. At December 31, 2011, the transmission revenue shortfall was $2.1 million. The IPUC ordered that Idaho Power advise the IPUC when the FERC has issued its order on rehearing, following which Idaho Power may request a commencement date for the amortization period for the regulatory asset. On December 7, 2011, the FERC issued an order denying rehearing. Accordingly, on February 15, 2012, Idaho Power submitted an application to the IPUC seeking to include the $2.1 million transmission revenue shortfall in customer rates, recoverable over a three-year period beginning June 1, 2012. As of the date of this report, a determination and order from the IPUC is pending.

Energy Efficiency and Demand Response Programs: Idaho Power has implemented and/or manages a wide range of opportunities for its customers to participate in energy efficiency and demand response programs.

On August 18, 2011, the IPUC issued an order approving Idaho Power's March 2011 application requesting that the IPUC designate Idaho Power's 2010 Idaho energy efficiency rider expenditures of approximately $42 million as prudently incurred expenses. Idaho Power’s 2010 expenditures for rider-funded energy efficiency and demand response initiatives in its Idaho and Oregon jurisdictions totaled $44.2 million. On March 16, 2010, Idaho Power filed an application with the IPUC requesting an order designating energy efficiency expenditures of $50.7 million incurred in 2008 and 2009 as prudently incurred expenses. On November 16, 2010, the IPUC issued an order designating all $50.7 million of energy efficiency expenditures as prudently incurred and approved for ratemaking purposes.

On October 22, 2010, Idaho Power filed an application with the IPUC requesting acceptance of the company's demand-side resources (DSR) business model, which included a request for authorization to (a) move demand response incentive payments out of the energy efficiency rider and into the Idaho PCA on a prospective basis beginning on June 1, 2011, and thus subject to a true-up under the PCA mechanism; (b) establish a regulatory asset for the direct incentive payments associated with Idaho Power's energy efficiency program for large commercial and industrial customers, beginning January 1, 2011, so that Idaho Power may capitalize the direct incentive payments associated with the program, include the costs associated with the program incentive payments in its rate base, and thus earn a rate of return on a portion of its DSR activities; and (c) change the carrying charge on the existing energy efficiency rider balancing account (from the then-current interest rate of 1.0 percent to Idaho Power's authorized rate of return). On April 1, 2011, the IPUC issued an order stating that certain issues raised in the application are more properly considered in a general rate case proceeding. However, the IPUC noted in its order that Idaho Power's energy efficiency rider balance includes approximately $10 million in expenditures that have been previously approved by the IPUC for recovery, and thus authorized recovery of $10 million of the rider balance in Idaho Power's Idaho PCA rates, beginning June 1, 2011. In that order, the IPUC did not approve a change to the energy efficiency rider balance carrying charge.

On May 17, 2011, the IPUC issued an order stating that it will allow Idaho Power to account for specified direct incentive payments associated with Idaho Power's energy efficiency program for large commercial and industrial customers as a regulatory asset beginning January 1, 2011, but with an amortization period to be determined later by the IPUC.

In its June 1, 2011 general rate case filing, Idaho Power requested authorization to treat demand response incentive payments as power supply costs and establish a base or "normal" level of cost recovery of approximately $11.3 million for those demand response incentive payments in rates. The Idaho general rate case settlement stipulation approved by the IPUC in December 2011 provides that the $11.3 million of base level demand response incentive payments would be tracked as part of the Idaho PCA mechanism. The December 2011 IPUC general rate case settlement order also reset Idaho Power's energy efficiency rider rate at 4.0 percent of the sum of the monthly billed charges for the base rate components, a reduction from the 4.75 percent rider amount in effect prior to that date.

Langley Gulch Power Plant Ratemaking Treatment: On September 1, 2009, Idaho Power received pre-approval from the IPUC to include $396.6 million of construction costs in Idaho Power’s rate base when the Langley Gulch power plant achieves commercial operation. Idaho Power may request recovery of additional costs if they exceed $396.6 million, provided that the additional costs were reasonably and prudently incurred.

Oregon Regulatory Matters

2011 Oregon General Rate Case: On July 29, 2011, Idaho Power filed a general rate case and proposed rate schedules with the OPUC, Case No. UE 233. The filing requested a $5.8 million increase in annual Oregon jurisdictional revenues which, if approved, would result in a 14.7 percent overall average rate increase for customers in the Oregon jurisdiction. The filing requested an authorized rate of return on equity of 10.5 percent with an Oregon retail rate base of approximately $121.9 million, and a rate of return on capital of 8.17 percent. Idaho Power, the OPUC Staff, and other interested parties executed and filed a partial settlement stipulation with the OPUC on February 1, 2012, which resolves all matters in the general rate case other than the prudence of costs associated with pollution control investments at the Jim Bridger coal plant. The settlement stipulation provides for a return on equity of 9.9 percent and an overall rate of return of 7.757 percent. If the stipulation is approved by the OPUC, Idaho Power expects that new rates will become effective on March 1, 2012. As of the date of this report, Idaho Power is unable to determine the outcome of the proceeding.

2009 Oregon General Rate Case: On February 24, 2010, the OPUC approved a $5 million, or 15.4 percent, increase in base rates in the Oregon jurisdiction. The new rates were effective March 1, 2010, and were based on a return on equity of 10.175 percent and an overall rate of return of 8.061 percent. Idaho Power’s previously authorized rate of return in Oregon was 7.83 percent.

Advanced Metering Infrastructure (AMI)

The AMI project provides the means to automatically retrieve energy consumption information, eliminating manual meter reading expense. On February 12, 2009, the IPUC approved Idaho Power’s application requesting a Certificate of Public Convenience and Necessity for the deployment of AMI technology and approval of accelerated depreciation for the existing metering equipment. The IPUC subsequently clarified that Idaho Power can expect to include in rate base the Idaho portion of prudent capital costs of deploying AMI as it is placed in service up to the capital cost commitment estimate of $70.9 million, plus certain costs that the company could not quantify with precision at the time of the application. The IPUC also clarified, as requested by Idaho Power, that it does not anticipate that the immediate savings derived from the implementation of AMI throughout Idaho Power's service territory will eliminate or wholly offset the increase in Idaho Power's revenue requirement caused by the authorized depreciation period.

On May 29, 2009, the IPUC approved annual recovery of $10.5 million, effective June 1, 2009. The order was based on Idaho Power's actual investment in AMI through the then-current date, annualized through December 31, 2009. The IPUC also allowed Idaho Power to begin three-year accelerated depreciation of the existing metering equipment on June 1, 2009. The order reflects annualized depreciation expense relating to AMI of $9.2 million. Actual depreciation expense recorded in 2011, 2010, and 2009 was $10.6 million, $10.6 million, and $6.2 million, respectively. On May 28, 2010, the IPUC approved Idaho Power's March 15, 2010 application requesting authorization to implement a $2.4 million base rate increase for identified customer classes to recover costs relating to the AMI project, with the rate increase effective June 1, 2010.

In the Oregon jurisdiction, the OPUC approved accelerated depreciation and recovery of existing meters located in Oregon over an 18-month period beginning January 2009. The approval increased both rates and depreciation expense by $0.8 million in 2009 and $0.4 million in 2010.

Idaho Power has completed the installation of substantially all smart meters associated with the AMI project. On February 15, 2012, Idaho Power filed an application with the IPUC requesting authority to decrease its Idaho-jurisdiction base rates by $10.6 million annually due to the removal of accelerated depreciation expense associated with non-AMI metering equipment. As of the date of this report, a determination and order from the IPUC is pending.

Depreciation Filings

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

In connection with a depreciation study authorized by Idaho Power and conducted by a third party, on February 15, 2012, Idaho Power filed an application with the IPUC seeking to institute revised depreciation rates for electric plant-in-service, based upon updated net salvage percentages and service life estimates for all plant assets, and adjust Idaho-jurisdictional base rates to reflect the revised depreciation rates. Idaho Power's application requested a $2.7 million increase in Idaho-jurisdictional base rates, with new rates effective June 1, 2012. As of the date of this report, a determination and order from the IPUC is pending.

Federal Open Access Transmission Tariff (OATT) Rates

In 2006, Idaho Power moved from a fixed rate to a formula rate for transmission service provided under its OATT, which allows transmission rates to be updated annually based on financial and operational data Idaho Power files with the FERC. Idaho Power's OATT rates submitted to the FERC in Idaho Power's four most recent annual OATT Final Informational Filings were as follows:

Applicable Period	OATT Rate (per KW-year)*
October 1, 2008 to September 30, 2009	$ 13.81
October 1, 2009 to September 30, 2010	$ 15.83
October 1, 2010 to September 30, 2011	$ 19.60
October 1, 2011 to September 30, 2012	$ 19.79

* In September 2010, Idaho Power made corrections to its OATT rates for the period beginning October 1, 2007 through September 30, 2010, which resulted in the issuance of a $0.5 million refund to transmission customers.

4. LONG-TERM DEBT

The following table summarizes long-term debt at December 31 (in thousands of dollars):

	2011	2010
First mortgage bonds:		
6.60% Series due 2011	$ —	$ 120,000
4.75% Series due 2012	100,000	100,000
4.25% Series due 2013	70,000	70,000
6.025% Series due 2018	120,000	120,000
6.15% Series due 2019	100,000	100,000
4.50% Series Due 2020	130,000	130,000
3.40% Series Due 2020	100,000	100,000
6% Series due 2032	100,000	100,000
5.50% Series due 2033	70,000	70,000
5.50% Series due 2034	50,000	50,000
5.875% Series due 2034	55,000	55,000
5.30% Series due 2035	60,000	60,000
6.30% Series due 2037	140,000	140,000
6.25% Series due 2037	100,000	100,000
4.85% Series due 2040	100,000	100,000
Total first mortgage bonds	1,295,000	1,415,000
Pollution control revenue bonds:		
5.15% Series due 2024(1)	49,800	49,800
5.25% Series due 2026(1)	116,300	116,300
Variable Rate Series 2000 due 2027	4,360	4,360
Total pollution control revenue bonds	170,460	170,460
American Falls bond guarantee	19,885	19,885
Milner Dam note guarantee	6,382	7,446
Unamortized premium/discount - net	(3,113)	(3,440)
Total Idaho Power outstanding debt(2)	1,488,614	1,609,351
Debt related to investments in affordable housing	—	1,508
Total IDACORP outstanding debt	1,488,614	1,610,859
Current maturities of long-term debt	(101,064)	(122,572)
Total long-term debt	$ 1,387,550	$ 1,488,287

(1) Humboldt County and Sweetwater County Pollution Control Revenue Bonds are secured by the first mortgage, bringing the total first mortgage bonds outstanding at December 31, 2011 to $1.461 billion.
(2) At December 31, 2011 and 2010, the overall effective cost of Idaho Power's outstanding debt was 5.43 percent and 5.53 percent, respectively.

At December 31, 2011, the maturities for the aggregate amount of IDACORP and Idaho Power long-term debt outstanding were (in thousands of dollars):

2012	2013	2014	2015	2016	Thereafter
$ 101,064	$ 71,064	$ 1,064	$ 1,064	$ 1,064	$ 1,316,407

IDACORP Long-Term Financing

As of December 31, 2011, IDACORP had approximately $539 million remaining on a shelf registration statement filed with the U.S. Securities and Exchange Commission (SEC) that can be used for the issuance of debt securities or IDACORP common stock. Common stock is discussed further in Note 6.

Idaho Power Long-Term Financing

In May 2010, Idaho Power registered with the SEC the issuance of up to $500 million of first mortgage bonds and debt securities. On June 17, 2010, Idaho Power entered into a selling agency agreement with ten banks named in the agreement in connection with the potential issuance and sale from time to time of up to $500 million aggregate principal amount of first mortgage bonds. As of December 31, 2011, $300 million remained on Idaho Power's shelf registration for the issuance of first mortgage bonds and debt securities.

On March 2, 2011, Idaho Power repaid at maturity $120 million of first mortgage bonds using proceeds from first mortgage bonds issued in August 2010.

On August 30, 2010, Idaho Power issued $100 million of 3.40% First Mortgage Bonds, Secured Medium-Term Notes, Series I due 2020 and $100 million of 4.85% First Mortgage Bonds, Secured Medium-Term Notes, Series I due 2040 under the shelf registration statement.

***Mortgage*:** As of December 31, 2011, Idaho Power could issue under its Indenture of Mortgage and Deed of Trust, dated as of October 1, 1937, between Idaho Power and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company) and R.G. Page, as Trustees (Stanley Burg, successor individual trustee) (Mortgage) approximately $1.3 billion of additional first mortgage bonds based on retired first mortgage bonds and total unfunded property additions. These amounts are further limited by the maximum amount of first mortgage bonds set forth in the Mortgage.

The Mortgage secures all bonds issued under the indenture equally and ratably, without preference, priority, or distinction. First mortgage bonds issued in the future will also be secured by the Mortgage. The lien of the indenture constitutes a first mortgage on all the properties of Idaho Power, subject only to certain limited exceptions including liens for taxes and assessments that are not delinquent and minor excepted encumbrances. Certain of the properties of Idaho Power are subject to easements, leases, contracts, covenants, workmen's compensation awards, and similar encumbrances and minor defects and clouds common to properties. The Mortgage does not create a lien on revenues or profits, or notes or accounts receivable, contracts or choses in action, except as permitted by law during a completed default, securities, or cash, except when pledged, or merchandise or equipment manufactured or acquired for resale. The Mortgage creates a lien on the interest of Idaho Power in property subsequently acquired, other than excepted property, subject to limitations in the case of consolidation, merger, or sale of all or substantially all of the assets of Idaho Power. The Mortgage requires Idaho Power to spend or appropriate 15 percent of its annual gross operating revenues for maintenance, retirement, or amortization of its properties. Idaho Power may, however, anticipate or make up these expenditures or appropriations within the five years that immediately follow or precede a particular year.

On February 17, 2010, Idaho Power entered into the Forty-fifth Supplemental Indenture, dated as of February 1, 2010, to the Mortgage for the purpose of increasing the maximum amount of first mortgage bonds issuable by Idaho Power from $1.5 to $2.0 billion. The amount issuable is also restricted by property, earnings, and other provisions of the Mortgage and supplemental indentures to the Mortgage. Idaho Power may amend the Mortgage and increase this amount without consent of the holders of the first mortgage bonds. The Mortgage requires that Idaho Power's net earnings be at least twice the annual interest requirements on all outstanding debt of equal or prior rank, including the bonds that Idaho Power may propose to issue. Under certain circumstances, the net earnings test does not apply, including the issuance of refunding bonds to retire outstanding bonds that mature in less than two years or that are of an equal or higher interest rate, or prior lien bonds.

5. NOTES PAYABLE

Credit Facilities

On October 26, 2011, IDACORP and Idaho Power entered into amended and restated credit agreements, which amended and restated their existing $100 million and $300 million credit facilities, respectively. The new credit facilities may be used for general corporate purposes and commercial paper backup. IDACORP's credit facility consists of a revolving line of credit not to exceed the aggregate principal amount at any one time outstanding of $125 million, including swingline loans in an aggregate principal amount at any time outstanding not to exceed $15 million, and letters of credit in an aggregate principal amount at any time outstanding not to exceed $50 million. Idaho Power's credit facility consists of a revolving line of credit, through the issuance of loans and standby letters of credit, not to exceed the aggregate principal amount at any one time outstanding of $300 million, including swingline loans in an aggregate principal amount at any time outstanding not to exceed $30 million. IDACORP and Idaho Power have the right to request an increase in the aggregate principal amount of the facilities to $150 million and $450 million, respectively, in each case subject to certain conditions. The credit facilities mature on October 26, 2016, although IDACORP and Idaho Power have the right to request up to 2 one-year extensions of the credit agreement, in each case subject to certain conditions.

The IDACORP and Idaho Power credit facilities have similar terms and conditions. The interest rates for any borrowings under the facilities are based on either (1) a floating rate that is equal to the highest of the prime rate, federal funds rate plus 0.5 percent, or LIBOR rate plus 1.0 percent, or (2) the LIBOR rate, plus, in each case, an applicable margin. The margin is based on IDACORP's or Idaho Power's, as applicable, senior unsecured long-term indebtedness credit rating by Moody's Investors Service, Inc., Standard and Poor's Ratings Services, and Fitch Rating Services, Inc., as set forth on a schedule to the credit agreements. Under their respective facilities, the companies pay a facility fee on the commitment based on the respective company's credit rating for senior unsecured long-term debt securities.

At December 31, 2011, no amounts were outstanding under either IDACORP's or Idaho Power's facilities. At December 31, 2011, Idaho Power had regulatory authority to incur up to $450 million of short-term indebtedness. Balances and interest rates of short-term borrowings of commercial paper were as follows at December 31 (in thousands of dollars):

	IDACORP		Idaho Power		Total	
	2011	**2010**	**2011**	**2010**	**2011**	**2010**
Commercial paper balances:						
At the end of year	$ 54,200	$ 66,900	$ —	$ —	$ 54,200	$ 66,900
Average during the year	$ 65,574	$ 19,754	$ —	$ 348	$ 65,574	$ 20,102
Weighted-average interest rate						
At the end of the year	0.47%	0.43%	—%	—%	0.47%	0.43%

6. COMMON STOCK

IDACORP Common Stock

The following table summarizes common stock transactions during the last three years and shares reserved at December 31, 2011:

	Shares issued			Shares reserved
	2011	**2010**	**2009**	**December 31, 2011**
Balance at beginning of year	49,419,452	47,925,882	46,929,203	
Continuous equity program	—	973,585	489,360	3,000,000
Dividend reinvestment and stock purchase plan	119,999	144,655	209,859	2,638,807
Employee savings plan	91,277	105,375	156,814	3,618,903
Long-term incentive and compensation plan	333,444	256,662	112,128	1,703,842
Restricted stock plan	—	13,293	28,518	256,154
Balance at end of year	49,964,172	49,419,452	47,925,882	

IDACORP enters into sales agency agreements as a means of selling its common stock from time to time pursuant to a continuous equity program. IDACORP's current sales agency agreement is with BNY Mellon Capital Markets, LLC. As of December 31, 2011, there were approximately 3 million shares remaining available to be sold under the current sales agency agreement. No shares were issued under the sales agency agreement in 2011. IDACORP sold 973,585 shares under the program in 2010 at an average price of $35.47 and 489,360 shares in 2009 at an average price of $28.79.

Idaho Power Common Stock

In 2011, 2010, and 2009, IDACORP contributed $16 million, $50 million, and $20 million, respectively, of additional equity to Idaho Power. No additional shares of Idaho Power common stock were issued in exchange for the contributions.

Restrictions on Dividends

A covenant under IDACORP's credit facility and Idaho Power's credit facility requires IDACORP and Idaho Power to maintain leverage ratios of consolidated indebtedness to consolidated total capitalization, as defined therein, of no more than 65 percent at the end of each fiscal quarter. Idaho Power's ability to pay dividends on its common stock held by IDACORP and IDACORP's ability to pay dividends on its common stock are limited to the extent payment of such dividends would violate the covenants in their respective credit facilities or Idaho Power's Revised Code of Conduct. At December 31, 2011, the leverage ratios for IDACORP and Idaho Power were 48 percent and 49 percent, respectively. Based on these restrictions, IDACORP's and Idaho Power's dividends were limited to $827 million and $723 million, respectively, at December 31, 2011. There are additional facility covenants, subject to exceptions, that prohibit certain mergers, acquisitions, and investments; restrict the creation of certain liens; and prohibit entering into any agreements restricting dividend payments to the company from any material subsidiary.

Idaho Power's Revised Code of Conduct, approved by the IPUC on April 21, 2008, states that Idaho Power will not pay any dividends to IDACORP that will reduce Idaho Power's common equity capital below 35 percent of its total adjusted capital without IPUC approval. Idaho Power's articles of incorporation also contain restrictions on the payment of dividends on its common stock if preferred stock dividends are in arrears. Idaho Power has no preferred stock outstanding.

In addition to contractual restrictions on the amount and payment of dividends, the Federal Power Act prohibits the payment of dividends from "capital accounts." The term "capital accounts" is undefined in the Federal Power Act, but if conservatively interpreted could limit the payment of dividends by Idaho Power to the amount of Idaho Power's retained earnings.

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

7. STOCK-BASED COMPENSATION

IDACORP has two share-based compensation plans -- the 2000 Long-Term Incentive and Compensation Plan (LTICP) and the 1994 Restricted Stock Plan (RSP). These plans are intended to align employee and shareholder objectives related to IDACORP's long-term growth.

The LTICP (for officers, key employees, and directors) permits the grant of nonqualified stock options, restricted stock, performance shares, and several other types of stock-based awards. The RSP permits only the grant of restricted stock or performance-based restricted stock. At December 31, 2011, the maximum number of shares available under the LTICP and RSP were 1,503,861 and 15,796, respectively.

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

Performance-based restricted stock awards have three-year vesting periods and entitle the recipients to voting rights. Unvested shares are restricted as to disposition, subject to forfeiture under certain circumstances, and subject to meeting specific performance conditions. Based on the attainment of the performance conditions, the ultimate award can range from zero to 150 percent of the target award. Dividends are accrued and paid out only on shares that eventually vest.

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

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

	IDACORP		Idaho Power	
	Number of Shares	Weighted-Average Grant Date Fair Value	Number of Shares	Weighted-Average Grant Date Fair Value
Nonvested shares at January 1, 2011	351,953	$ 26.35	329,501	$ 26.35
Shares granted	136,644	30.30	135,016	30.30
Shares forfeited	(11,451)	27.32	(11,451)	27.32
Shares vested	(137,208)	25.28	(115,883)	25.28
Nonvested shares at December 31, 2011	339,938	$ 26.40	337,183	$ 26.40

The total fair value of shares vested during the years ended December 31, 2011, 2010, and 2009 was $4.1 million, $3.3 million, and $3.9 million, respectively. At December 31, 2011, IDACORP had $4 million of total unrecognized compensation cost related to nonvested share-based compensation that was expected to vest. Idaho Power's share of this amount was $4 million. These costs are expected to be recognized over a weighted-average period of 1.68 years. IDACORP uses original issue and/or treasury shares for these awards.

In 2011, a total of 11,920 shares were awarded to directors at a grant date fair value of $37.74 per share. Directors elected to defer receipt of 5,960 of these shares, which are being held as deferred stock units with dividend equivalents reinvested in additional stock units.

Stock Options: No stock options have been granted since 2006. The remaining unexercised stock option awards were granted with exercise prices equal to the market value of the stock on the date of grant, with a term of 10 years from the grant date and a five-year vesting period. The fair value of each option was amortized into compensation expense using graded vesting and, as of December 31, 2011, all compensation costs have been recognized. IDACORP uses original issue and/or treasury shares to satisfy exercised options.

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

	Number of Shares	Weighted-Average Exercise Price	Weighted Average Remaining Contractual Term (Years)	Aggregate Intrinsic Value (000s)
IDACORP				
Outstanding at December 31, 2010	385,785	$ 37.47	1.12	$ 541
Exercised	(255,746)	36.84		
Expired	(102,233)	39.89		
Outstanding at December 31, 2011	27,806	$ 32.29	1.75	$ 281
Vested and exercisable at December 31, 2011	27,806	$ 32.29	1.75	$ 281
Idaho Power				
Outstanding at December 31, 2010	202,634	$ 38.05	1.13	$ 314
Exercised	(90,945)	35.54		
Expired	(102,233)	39.89		
Outstanding at December 31, 2011	9,456	$ 33.67	1.58	$ 83
Vested and exercisable at December 31, 2011	9,456	$ 33.67	1.58	$ 83

The following table presents information about options vested and exercised (in thousands of dollars):

	IDACORP			Idaho Power		
	2011	2010	2009	2011	2010	2009
Fair value of options vested	$ —	$ 110	$ 266	$ —	$ 96	$ 208
Intrinsic value of options exercised	884	1,491	204	535	1,475	204
Cash received from exercises	9,423	5,475	591	3,838	5,394	591
Tax benefits realized from exercises	345	583	80	209	577	80

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

	IDACORP			Idaho Power		
	2011	2010	2009	2011	2010	2009
Compensation cost	$ 4,207	$ 3,706	$ 4,199	$ 4,082	$ 3,489	$ 3,986
Income tax benefit	1,645	1,449	1,642	1,596	1,364	1,587

No equity compensation costs have been capitalized.

8. EARNINGS PER SHARE

The following table presents the computation of IDACORP's basic and diluted earnings per share (EPS) for the years ended December 31, 2011, 2010, and 2009 (in thousands, except for per share amounts):

	Year Ended December 31,		
	2011	2010	2009
Numerator:			
Net income attributable to IDACORP, Inc.	$ 166,693	$ 142,798	$ 124,350
Denominator:			
Weighted-average common shares outstanding - basic	49,457	48,193	47,124
Effect of dilutive securities:			
Options	16	32	16
Restricted Stock	85	115	42
Weighted-average common shares outstanding - diluted	49,558	48,340	47,182
Basic earnings per share	$ 3.37	$ 2.96	$ 2.64
Diluted earnings per share	$ 3.36	$ 2.95	$ 2.64

The diluted EPS computation excludes 137,880, 332,182, and 594,107 options for the years ended December 31, 2011, 2010 and 2009, respectively, because the options' exercise prices were greater than the average market price of the common stock during that year. In total, 27,806 options were outstanding at December 31, 2011, with expiration dates between 2012 and 2015.

9. COMMITMENTS

Purchase Obligations

At December 31, 2011, Idaho Power had the following long-term commitments relating to purchases of energy, capacity, transmission rights, and fuel (in thousand of dollars):

	2012	2013	2014	2015	2016	Thereafter
Cogeneration and power production	$ 165,693	$ 196,261	$ 209,295	$ 214,960	$ 218,220	$3,687,810
Power and transmission rights	10,772	4,243	3,188	2,210	1,879	4,401
Fuel	79,138	64,852	66,309	22,661	8,909	98,212

As of December 31, 2011, Idaho Power had signed agreements to purchase energy from 119 CSPP facilities with contracts ranging from one to 35 years. Ninety-six of these facilities, with a combined nameplate capacity of 606 MW, were on-line at the end of 2011; the other 23 facilities under contract, with a combined nameplate capacity of 383 MW, are projected to come on-line by year end 2014. The majority of the new facilities will be wind resources which will generate on an intermittent basis. During 2011, Idaho Power purchased 1,495,108 megawatt-hours (MWh) from these projects at a cost of $90 million, resulting in a blended price of $60.36 per MWh. Idaho Power purchased 910,429 MWh at a cost of $55 million in 2010, and 970,419 MWh at a cost of $59 million in 2009.

In addition, IDACORP has the following long-term commitments for lease guarantees, equipment, maintenance and services, and industry related fees (in thousand of dollars:

	2012	2013	2014	2015	2016	Thereafter
Operating leases	$ 2,041	$ 2,875	$ 2,768	$ 2,199	$ 1,203	$ 15,711
Equipment, maintenance, and service agreements	38,553	15,271	6,169	4,897	3,700	8,254
FERC and other industry-related fees	12,391	12,031	9,745	9,745	6,596	32,981

IDACORP’s expense for operating leases was approximately $5.3 million in 2011, $3.4 million in 2010, and $3.5 million in 2009.

Guarantees

Idaho Power has agreed to guarantee a portion of the performance of reclamation activities and obligations at BCC, of which IERCo owns a one-third interest. This guarantee, which is renewed each December, was $63 million at December 31, 2011, representing IERCo's one-third share of BCC's total reclamation obligation of $189 million. BCC has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. As of December 31, 2011, the value of the reclamation trust fund totaled $80 million. BCC periodically assesses the adequacy of the reclamation trust fund and its estimate of future reclamation costs. To ensure that the reclamation trust fund maintains adequate reserves, BCC has the ability to add a per-ton surcharge to coal sales. Starting in 2010, BCC began applying a nominal surcharge to coal sales in order to maintain adequate reserves in the reclamation trust fund. Because of the existence of the fund and the ability to apply a per-ton surcharge, the estimated fair value of this guarantee is minimal.

IDACORP and Idaho Power enter into financial agreements and power purchase and sale agreements that include indemnification provisions relating to various forms of claims or liabilities that may arise from the transactions contemplated by these agreements. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnification provisions cannot be reasonably estimated. IDACORP and Idaho Power periodically evaluate the likelihood of incurring costs under such indemnities based on their historical experience and the evaluation of the specific indemnities. As of December 31, 2011, management believes the likelihood is remote that IDACORP or Idaho Power would be required to perform under such indemnification provisions or otherwise incur any significant losses with respect to such indemnification obligations. Neither IDACORP nor Idaho Power has recorded any liability on their respective consolidated balance sheets with respect to these indemnification obligations.

10. CONTINGENCIES

IDACORP and Idaho Power have in the past and expect in the future to become involved in various claims, controversies, disputes, and other contingent matters, including the items described in this Note 10. Some of these claims, controversies, disputes, and other contingent matters involve litigation and regulatory or other contested proceedings. IDACORP and Idaho Power intend to vigorously protect and defend their interests and pursue their rights. However, the ultimate resolution and outcome of litigation and regulatory proceedings is inherently difficult to determine, particularly where (a) the remedies or penalties sought are indeterminate, (b) the proceedings are in the early stages or the substantive issues have not been well developed, or (c) the matters involve complex or novel legal theories or a large number of parties. In accordance with applicable accounting guidance, IDACORP and Idaho Power, as applicable, establish an accrual for legal proceedings when those matters proceed to a stage where they present loss contingencies that are both probable and reasonably estimable. In such cases, there may be a possible exposure to loss in excess of any amounts accrued. IDACORP and Idaho Power monitor those matters for developments that could affect the likelihood of a loss and the accrued amount, if any, thereof, and adjust the amount as appropriate. If the loss contingency at issue is not both probable and reasonably estimable, IDACORP and Idaho Power do not establish an accrual and the matter will continue to be monitored for any developments that would make the loss contingency both probable and reasonably estimable. As of the date of this report, IDACORP's and Idaho Power's accruals for legal proceedings are not material to their financial statements as a whole; however, future accruals could be material in a given period. IDACORP's and Idaho Power's determination is based on currently available information, and estimates presented in financial statements and other financial disclosures involve significant judgment and may be subject to significant uncertainty. As available information changes, the matters for which IDACORP and Idaho Power are able to estimate the loss may change, and the estimates themselves may change.

For certain of those matters described in this report for which IDACORP or Idaho Power have determined a loss contingency may, in the future, be at least reasonably possible, IDACORP and Idaho Power have stated that they are unable to estimate the possible loss or a range of possible loss that may result from those matters. Depending on a range of factors, such as the complexity of the facts, the unique nature of the legal theories, the pace of discovery, the timing of court decisions, and the adverse party's willingness to negotiate towards a resolution, it may be months or years after the filing of a case before IDACORP or Idaho Power may be in a position to estimate the possible loss or range of possible loss for those matters.

Given the substantial or indeterminate amounts sought in certain of the matters described below, and the inherent unpredictability of such matters, an adverse outcome in certain of these matters could have a material adverse effect on IDACORP's and Idaho Power's financial condition, results of operations, or cash flows in particular quarterly or annual periods. For matters that affect Idaho Power’s operations, Idaho Power intends to seek, to the extent permissible and appropriate, recovery of incurred costs through the ratemaking process.

Western Energy Proceedings

High prices for electricity, energy shortages, and blackouts in California and in western wholesale markets during 2000 and 2001 caused numerous purchasers of electricity in those markets to initiate proceedings seeking refunds or other forms of relief and the FERC to initiate its own investigations. Some of these proceedings remain pending before the FERC or are on appeal to the United States Court of Appeals for the Ninth Circuit (Ninth Circuit). Except as to the matters described below under “Pacific Northwest Refund,” Idaho Power and IE believe that settlement releases they have obtained will restrict potential claims that might result from the disposition of the pending Ninth Circuit review petitions and predict that these matters will not have a material adverse effect on their consolidated financial positions, results of operations, or cash flows.

Pacific Northwest Refund: On July 25, 2001, the FERC issued an order establishing a proceeding to determine whether there may have been unjust and unreasonable charges for spot market sales in the Pacific Northwest during the period December 25, 2000 through June 20, 2001, because the spot market in the Pacific Northwest was affected by the dysfunction in the California market. During that period, Idaho Power or IE both sold and purchased electricity in the Pacific Northwest. In 2003, the FERC terminated the proceeding and declined to order refunds, but in 2007 the Ninth Circuit issued an opinion, in *Port of Seattle, Washington v. FERC*, remanding to the FERC the orders that declined to require refunds. The Ninth Circuit's opinion instructed the FERC to consider whether evidence of market manipulation would have altered the agency's conclusions about refunds and directed the FERC to include sales originating in the Pacific Northwest to the California Department of Water Resources (CDWR) in the scope of the proceeding. The Ninth Circuit officially returned the case to the FERC on April 16, 2009. On October 3, 2011, the FERC issued its order on remand. The FERC ordered that the record be re-opened to permit parties seeking refunds to submit seller-specific evidence in support of their claims for sales made during the period confined to December 25, 2000 through June 20, 2001. The seller-specific claims must show that a seller engaged in unlawful market activity with a causal connection to have directly affected the negotiation of the specific contract or contracts to which the seller was a party. Neither claims of general dysfunction in the California markets nor in the Pacific Northwest market will be sufficient to support claims. While directing a trial-type hearing, the FERC also directed that the hearings be held in abeyance so that the matter may be presented to a settlement judge. On November 2, 2011, each of the City of Seattle, Washington, the City of Tacoma, Washington, the Port of Seattle, and the California Parties (consisting of the California Attorney General and the California Public Utilities Commission) filed requests for rehearing, seeking to expand the scope of the October 3, 2011 order. The designated settlement judge has met with the parties and convened a settlement conference to establish settlement procedures. The FERC's Chief Administrative Law Judge memorialized certain settlement procedures to which the parties agreed in an order issued on November 23, 2011.

IE and Idaho Power intend to continue to defend their positions in the Pacific Northwest refund proceedings vigorously. As of the date of this report, it is difficult to predict the outcome of this matter. Idaho Power does not believe that claims conforming to the requirements of the FERC's October 3, 2011 order have been submitted, and the FERC's order remains subject to rehearing and reconsideration. Idaho Power and IE are unable to predict when and how the FERC will act on the rehearing requests, which contracts would be subject to refunds, whether the FERC will order refunds, or how the refunds would be calculated. As a result of these factors, as of the date of this report Idaho Power and IE are unable to estimate the reasonably possible loss or range of losses that Idaho Power or IE could incur as a result of this matter. However, based on the status of settlement discussions with one party to the proceedings, for that portion of the matter Idaho Power reserved for a contingent liability an amount immaterial to IDACORP's or Idaho Power's financial statements in the fourth quarter of 2011.

EPA Notice of Violation - Boardman

In September 2010, the U.S. Environmental Protection Agency (EPA) issued a Notice of Violation to Portland General Electric Company (PGE), alleging that PGE had violated the New Source Performance Standards (NSPS) and operating permit requirements under the Clean Air Act (CAA) as a result of modifications made to the Boardman coal-fired plant in 1998 and 2004. PGE is the operator of the Boardman plant, and Idaho Power has a 10 percent ownership interest in the plant. The Notice of Violation states the maximum civil penalties the EPA is authorized to impose under the CAA for violations of the NSPS (which range from $25,000 to $37,500 per day), but it does not impose any penalties or specify the amount of any proposed penalties with respect to the alleged violations. It is difficult to meaningfully predict the eventual outcome of this matter given the complexity of the environmental statutes and claims cited in the Notice of Violation and the matters at issue, the unspecified nature of the penalty or other remedy sought, and the absence of factual information given the early stage of the proceedings. As of the date of this report, based on available information and the status of this matter, Idaho Power is unable to estimate the reasonably possible loss or range of losses that Idaho Power could incur as a result of this matter. However, PGE, the plant operator, has stated that based on its understanding of the penalties authorized under the CAA, the maximum penalty that could be imposed for the alleged violations is approximately $60 million, with Idaho Power's share of any such penalty being limited to 10 percent of the amount ultimately assessed, if any.

Water Rights - Snake River Basin Adjudication

Idaho Power holds water rights, acquired under applicable state law, for its hydroelectric projects. In addition, Idaho Power holds water rights for domestic, irrigation, commercial, and other necessary purposes related to project lands and other holdings within the states of Idaho and Oregon. Idaho Power's water rights for power generation are, to varying degrees, subordinated to future upstream appropriations for irrigation and other authorized consumptive uses.

Over time, increased irrigation development and other consumptive uses within the Snake River watershed led to a reduction in flows of the Snake River. In the late 1970's and early 1980's these reduced flows resulted in a conflict between the exercise of Idaho Power's water rights at certain hydroelectric projects on the Snake River and upstream consumptive diversions. The Swan Falls Agreement, signed by Idaho Power and the State of Idaho on October 25, 1984, resolved the conflict and provided a level of protection for Idaho Power's hydropower water rights at specified projects on the Snake River through the establishment of minimum stream flows and an administrative process governing future development of water rights that may affect those minimum stream flows. In 1987, Congress enacted legislation directing the FERC to issue an order approving the Swan Falls settlement together with a finding that the agreement was neither inconsistent with the terms and conditions of Idaho Power's project licenses nor the Federal Power Act. The FERC entered an order implementing the legislation on March 25, 1988.

The Swan Falls Agreement provided that the resolution and recognition of Idaho Power's water rights together with the State

Water Plan provided a sound comprehensive plan for management of the Snake River watershed. The Swan Falls Agreement also recognized, however, that in order to effectively manage the waters of the Snake River basin, a general adjudication to determine the nature, extent, and priority of the rights of all water uses in the basin was necessary. Consistent with that recognition, in 1987 the State of Idaho initiated the Snake River Basin Adjudication (SRBA), and pursuant to the commencement order issued by the SRBA court that same year, all claimants to water rights within the basin were required to file water rights claims in the SRBA. Idaho Power has filed claims to its water rights and has been actively participating in the SRBA since its commencement. Questions concerning the effect of the Swan Falls Agreement on Idaho Power's water rights claims, including the nature and extent of the subordination of Idaho Power's rights to upstream uses, resulted in the filing of litigation in the SRBA in 2007 between Idaho Power and the State of Idaho. This litigation was resolved by the Framework Reaffirming the Swan Falls Settlement (Framework) signed by Idaho Power and the State of Idaho on March 25, 2009. In that Framework, the parties acknowledged that the effective management of Idaho's water resources remains critical to the public interest of the State of Idaho by sustaining economic growth, maintaining reasonable electric rates, protecting and preserving existing water rights, and protecting water quality and environmental values. The Framework further provided that the State of Idaho and Idaho Power would cooperate in exploring approaches to resolve issues of mutual concern relating to the management of Idaho's water resources. Idaho Power continues to work with the State of Idaho and other interested parties on these issues.

One such issue involves the management of the Eastern Snake Plain Aquifer (ESPA), a large underground aquifer in southeastern Idaho that is hydrologically connected to the Snake River. House Concurrent Resolution No. 28, adopted by the Idaho Legislature in 2007, directed the Idaho Water Resource Board to pursue the development of a comprehensive management plan for the ESPA, to include measures that would enhance aquifer levels, springs, and river flows on the eastern Snake River plain to the benefit of both agricultural development and hydropower generation. In May of 2007, the Idaho Water Resource Board appointed an advisory committee, charged with the responsibility of developing a management plan for the ESPA. Idaho Power was a member of that committee. In January 2009, the Idaho Water Resource Board, based on the committee's recommendations, adopted a Comprehensive Aquifer Management Plan (CAMP) for the ESPA. The Idaho Legislature approved the CAMP that same year. Idaho Power is a member of the CAMP Implementation Committee and continues to work with the Idaho Water Resource Board, other stakeholders, and the Idaho Legislature in exploring opportunities for implementation of the CAMP management plan.

Idaho Power also continues its active participation in the SRBA in seeking to ensure that its water rights are protected and that the operation of its hydroelectric projects is not adversely impacted. While Idaho Power cannot predict the outcome, Idaho Power does not anticipate any material modification of its water rights as a result of the SRBA process.

Other Legal Proceedings

IDACORP and Idaho Power are parties to legal claims, actions, and proceedings in addition to those discussed above. However, as of the date of this report the companies believe that resolution of these matters will not have a material adverse effect on their consolidated financial positions, results of operations, or cash flows.

11. BENEFIT PLANS

Pension Plans

Idaho Power has a noncontributory defined benefit pension plan covering most employees. The benefits under the plan are based on years of service and the employee’s final average earnings. Idaho Power’s policy is to fund, with an independent corporate trustee, at least the minimum required under the Employee Retirement Income Security Act of 1974 (ERISA) but not more than the maximum amount deductible for income tax purposes. In 2011 and 2010 Idaho Power elected to contribute more than the minimum required amounts in order to bring the plan to a more funded position, to reduce future required contributions, and to reduce Pension Benefit Guaranty Corporation premiums. Idaho Power was not required to contribute to the plan in 2009. The market-related value of assets for the plan is equal to the fair value of the assets. Fair value is determined by utilizing publicly quoted market values and independent pricing services depending on the nature of the asset, as reported by the trustee/custodian of the plan.

In addition, Idaho Power has a nonqualified, deferred compensation plan for certain senior management employees and directors called the Senior Management Security Plan (SMSP). At December 31, 2011 and 2010, approximately $41.2 million and $46.2 million, respectively, of life insurance policies and investments in marketable securities, all of which are held by a trustee, were designated to satisfy the projected benefit obligation of the plan but do not qualify as plan assets in the actuarial computation of the funded status.

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

	Pension Plan		SMSP	
	2011	2010	2011	2010
Change in benefit obligation:				
Benefit obligation at January 1	$ 569,934	$ 506,744	$ 59,126	$ 52,719
Service cost	20,478	17,671	1,950	1,541
Interest cost	30,322	29,119	3,094	3,004
Actuarial loss	55,535	35,909	4,251	5,186
Benefits paid	(20,830)	(19,509)	(3,378)	(3,324)
Benefit obligation at December 31	655,439	569,934	65,043	59,126
Change in plan assets:				
Fair value at January 1	397,003	313,474	—	—
Actual return on plan assets	(4,592)	43,038	—	—
Employer contributions	18,500	60,000	—	—
Benefits paid	(20,830)	(19,509)	—	—
Fair value at December 31	390,081	397,003	—	—
Funded status at end of year	$ (265,358)	$ (172,931)	$ (65,043)	$ (59,126)
Amounts recognized in the statement of financial position consist of:				
Other current liabilities	$ —	$ —	$ (3,496)	$ (3,289)
Noncurrent liabilities	(265,358)	(172,931)	(61,547)	(55,837)
Net amount recognized	$ (265,358)	$ (172,931)	$ (65,043)	$ (59,126)
Amounts recognized in accumulated other comprehensive income consist of:				
Net loss	$ 245,632	$ 161,855	$ 21,799	$ 18,840
Prior service cost	1,335	1,855	1,502	1,744
Subtotal	246,967	163,710	23,301	20,584
Less amount recorded as regulatory asset	(246,967)	(163,710)	—	—
Net amount recognized in accumulated other comprehensive income	$ —	$ —	$ 23,301	$ 20,584
Accumulated benefit obligation	$ 549,503	$ 482,448	$ 59,836	$ 54,213

The following table shows the components of net periodic benefit cost for these plans (in thousands of dollars):

	Pension Plan			SMSP		
	2011	2010	2009	2011	2010	2009
Service cost	$ 20,478	$ 17,671	$ 16,514	$ 1,950	$ 1,541	$ 1,610
Interest cost	30,322	29,119	27,865	3,094	3,004	2,854
Expected return on assets	(32,322)	(26,463)	(23,965)	—	—	—
Amortization of net loss	8,673	7,675	8,857	1,293	931	659
Amortization of prior service cost	519	650	650	242	233	232
Net periodic pension cost	27,670	28,652	29,921	6,579	5,709	5,355
Adjustment to cost recognized due to the effects of regulation[1]	6,662	(24,104)	(28,669)	—	—	—
Net periodic benefit cost recognized for financial reporting	$ 34,332	$ 4,548	$ 1,252	$ 6,579	$ 5,709	$ 5,355

[1] Net periodic benefit costs for the pension plan are recognized based on the authorization of each regulatory jurisdiction Idaho Power operates within. Under IPUC order, income statement recognition of pension plan costs is deferred until costs are recovered through rates. See Note 3 for information on Idaho Power's 2011 Idaho pension rate order, which increased Idaho-jurisdiction recovery to $17.1 million annually, effective June 1, 2011, and also for information on Idaho Power's sharing mechanism, which resulted in additional Idaho pension amortization of $20.3 million in 2011.

In 2012, IDACORP and Idaho Power expect to recognize as components of net periodic benefit cost $15.9 million from amortizing amounts recorded in accumulated other comprehensive income (or as a regulatory asset for the pension plan) as of December 31, 2011, relating to the pension and SMSP plans. This amount consists of $13.9 million of amortization of net loss and $0.3 million of amortization of prior service cost for the pension plan, and $1.5 million of amortization of net loss and $0.2 million of amortization of prior service cost for the SMSP.

The following table summarizes the expected future benefit payments of these plans (in thousands of dollars):

	2012	2013	2014	2015	2016	2017-2021
Pension Plan	$ 22,360	$ 24,001	$ 25,684	$ 27,597	$ 29,761	$ 186,450
SMSP	3,578	3,707	3,899	4,063	4,084	22,797

As of December 31, 2011, IDACORP's and Idaho Power's minimum required contributions to the defined benefit pension plan are estimated to be approximately $34 million in 2012, $44 million in 2013, $44 million in 2014, $42 million in 2015, and $42 million in 2016. IDACORP and Idaho Power may elect to make contributions earlier than the required dates.

Postretirement Benefits

Idaho Power maintains a defined benefit postretirement benefit plan (consisting of health care and death benefits) that covers all employees who were enrolled in the active group plan at the time of retirement as well as their spouses and qualifying dependents. Retirees hired on or after January 1, 1999 have access to the standard medical option at full cost, with no contribution by Idaho Power. Benefits for employees who retire after December 31, 2002 are limited to a fixed amount, which has limited the growth of Idaho Power's future obligations under this plan.

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

	2011	2010
Change in accumulated benefit obligation:		
Benefit obligation at January 1	$ 68,048	$ 62,647
Service cost	1,323	1,276
Interest cost	3,434	3,578
Actuarial loss	(2,850)	3,291
Benefits paid[1]	(2,968)	(3,373)
Plan amendments	(318)	629
Benefit obligation at December 31	66,669	68,048
Change in plan assets:		
Fair value of plan assets at January 1	33,176	30,892
Actual return on plan assets	1,065	3,381
Employer contributions	628	2,276
Benefits paid[1]	(2,968)	(3,373)
Fair value of plan assets at December 31	31,901	33,176
Funded status at end of year (included in noncurrent liabilities)	$ (34,768)	$ (34,872)

[1] Benefits paid are net of $3,405 and $2,971 of plan participant contributions, and $444 and $415 of Medicare Part D subsidy receipts for 2011 and 2010, respectively.

Amounts recognized in accumulated other comprehensive income consist of the following (in thousands of dollars):

	2011	2010
Net loss	$ 14,112	$ 15,963
Prior service credit	(323)	(426)
Transition obligation	2,040	4,080
Subtotal	15,829	19,617
Less amount recognized in regulatory assets	(15,536)	(19,032)
Less amount included in deferred tax assets	(293)	(585)
Net amount recognized in accumulated other comprehensive income	$ —	$ —

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

	2011	2010	2009
Service cost	$ 1,323	$ 1,276	$ 1,221
Interest cost	3,434	3,578	3,565
Expected return on plan assets	(2,641)	(2,503)	(2,146)
Amortization of net loss	577	562	842
Amortization of prior service cost	(421)	(482)	(535)
Amortization of unrecognized transition obligation	2,040	2,040	2,040
Net periodic postretirement benefit cost	$ 4,312	$ 4,471	$ 4,987

In 2012, IDACORP and Idaho Power expect to recognize as components of net periodic benefit cost $2.2 million from amortizing amounts recorded in accumulated other comprehensive income as of December 31, 2011 relating to the postretirement benefit plan. This amount consists of $(0.4) million of prior service cost, $0.6 million of net loss, and $2.0 million of transition obligation.

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

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

	2012	2013	2014	2015	2016	2017-2021
Expected benefit payments	$ 4,176	$ 4,261	$ 4,415	$ 4,543	$ 4,620	$ 23,849
Expected Medicare Part D subsidy receipts	478	524	563	612	671	4,441

Plan Assumptions

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

	Pension Plan		SMSP		Postretirement Benefits	
	2011	2010	2011	2010	2011	2010
Discount rate	4.90%	5.40%	5.10%	5.40%	5.05%	5.40%
Rate of compensation increase[(1)]	4.35%	4.50%	4.50%	4.50%	—	—
Medical trend rate	—	—	—	—	7.0%	7.5%
Dental trend rate	—	—	—	—	5%	5%
Measurement date	12/31/2011	12/31/2010	12/31/2011	12/31/2010	12/31/2011	12/31/2010

[(1)] The 2011 rate of compensation increase assumption for the pension plan includes an inflation component of 2.75% plus a 1.60% composite merit increase component that is based on employees' years of service. Merit salary increases are assumed to be 8.0% for employees in their first year of service and scale down to 0% for employees in the fortieth year of service and beyond.

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

	Pension Plan			SMSP			Postretirement Benefits		
	2011	2010	2009	2011	2010	2009	2011	2010	2009
Discount rate	5.40%	5.90%	6.10%	5.40%	5.90%	6.10%	5.40%	5.90%	6.10%
Expected long-term rate of return on assets	8.25%	8.25%	8.50%	—	—	—	8.25%	8.25%	8.50%
Rate of compensation increase	4.50%	4.50%	4.50%	4.50%	4.50%	4.50%	—	—	—
Medical trend rate	—	—	—	—	—	—	7.0%	7.5%	8.0%
Dental trend rate	—	—	—	—	—	—	5.0%	5.0%	5.0%

The assumed health care cost trend rate used to measure the expected cost of health benefits covered by the postretirement plan was 7.0 percent and 7.5 percent in 2011 and 2010, respectively. The assumed health care cost trend rate for 2011 is assumed to decrease gradually to 4.9 percent by 2083. The assumed dental cost trend rate used to measure the expected cost of dental benefits covered by the plan was 5.0 percent in both 2011 and 2010. The assumed dental cost trend rate for 2011 is assumed to decrease gradually to 4.9 percent by 2083. A one percentage point change in the assumed health care cost trend rate would have the following effects at December 31, 2011 (in thousands of dollars):

	One-Percentage-Point	
	Increase	Decrease
Effect on total of cost components	$ 342	$ (255)
Effect on accumulated postretirement benefit obligation	2,939	(2,300)

Plan Assets

Pension Asset Allocation Policy: The target allocation and actual allocations at December 31, 2011 for the pension asset portfolio by asset class is set forth below.

Asset Class	Target Allocation	Actual Allocation December 31, 2011
Debt securities	24%	25%
Equity securities	54%	54%
Real estate	6%	6%
Other plan assets	16%	15%
Total	100%	100%

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

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

The three major goals in Idaho Power's asset allocation process are to:

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

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

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

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

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

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

If the inputs used to measure the securities fall within different levels of the hierarchy, the categorization is based on the lowest level input (Level 3 being the lowest) that is significant to the fair value measurement of the security. The following table sets forth by level within the fair value hierarchy a summary of the plans' investments measured at fair value on a recurring basis at December 31, 2011 (in thousands of dollars):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
Assets at December 31, 2011				
Pension assets:				
Cash and cash equivalents	$ 6,141	$ —	$ —	$ 6,141
Short-term bonds	—	23,443	—	23,443
Long-term bonds	—	74,658	—	74,658
Equity Securities: Large-Cap	51,780	—	—	51,780
Equity Securities: Mid-Cap	17,961	14,002	—	31,963
Equity Securities: Small-Cap	31,825	—	—	31,825
Equity Securities: Micro-Cap	16,087	—	—	16,087
Equity Securities: International	30,444	32,118	—	62,562
Equity Securities: Emerging Markets	1,745	15,112	—	16,857
Real estate	—	—	25,119	25,119
Private market investments	—	—	27,786	27,786
Commodities funds	2,929	18,931	—	21,860
Total pension assets	$ 158,912	$ 178,264	$ 52,905	$ 390,081
Postretirement assets[2]	$ —	$ 31,901	$ —	$ 31,901
Assets at December 31, 2010				
Pension assets:				
Cash and cash equivalents	$ 16,837	$ —	$ —	$ 16,837
Short-term bonds[1]	—	30,241	—	30,241
Core bonds[1]	—	43,156	—	43,156
Equity Securities: Large-Cap	58,961	—	—	58,961
Equity Securities: Mid-Cap	17,775	14,261	—	32,036
Equity Securities: Small-Cap	35,278	—	—	35,278
Equity Securities: Micro-Cap	17,422	—	—	17,422
Equity Securities: International	32,655	33,874	—	66,529
Equity Securities: Emerging Markets	2,199	18,241	—	20,440
Real estate	—	—	22,069	22,069
Private market investments	—	—	29,932	29,932
Commodities funds	3,406	20,696	—	24,102
Total pension assets	$ 184,533	$ 160,469	$ 52,001	$ 397,003
Postretirement assets[2]	$ —	$ 33,176	$ —	$ 33,176

[1] Subsequent to the issuance of the 2010 consolidated financial statements, IDACORP and Idaho Power determined these investments had previously been incorrectly categorized as Level 1 investments within the fair value hierarchy. As a result, the 2010 amounts have been restated to reflect the investments as Level 2.
[2] The postretirement benefits assets are primarily life insurance contracts.

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

	Private Equity	Real Estate	Total
Beginning balance - January 1, 2010	$ 20,202	$ 20,783	$ 40,985
Realized losses	—	(47)	(47)
Unrealized gains	1,284	2,211	3,495
Purchases, issuances, and settlements, net	8,446	(878)	7,568
Ending balance - December 31, 2010	29,932	22,069	52,001
Realized gains	—	598	598
Realized losses	(133)	—	(133)
Unrealized gains	1,425	1,854	3,279
Purchases, issuances, and settlements, net	(3,438)	598	(2,840)
Ending balance - December 31, 2011	$ 27,786	$ 25,119	$ 52,905

Fair Value Measurement of Level 2 and Level 3 Plan Asset Inputs

Level 2 Bonds, Equity Securities, and Level 2 Commodities: These investments represent U.S. government and agency bonds, corporate bonds, and commingled funds consisting of publicly traded equity securities or exchange-traded commodity contracts and other contractual claims to commodity holdings. The U.S. government and agency bonds, as well as the corporate bonds, are not traded on an exchange and are valued utilizing quoted prices for similar assets or liabilities in active markets. The commingled funds themselves are not publicly traded, and therefore no publicly quoted market price is readily available. The value of these investments is calculated by the custodian for the fund company on a monthly basis, and is based on market prices of the assets held by the commingled fund divided by the number of fund shares outstanding.

Level 3 Real Estate: Real estate holdings represent investments in open-ended commingled real estate funds. As the property interests held in these real estate funds are not frequently traded, establishing the market value of the property interests held by the fund, and the resulting unit value of fund shareholders, is based on unobservable inputs including property appraisals by the fund company, property appraisals by independent appraisal firms, analysis of the replacement cost of the property, discounted cash flows generated by property rents and changes in property values, and comparisons with sale prices of similar properties in similar markets. These open-ended real estate funds also furnish annual audited financial statements that are also used to further validate the information provided.

Level 3 Private Market Investments: Private market investments represent two categories: fund of hedge funds and venture capital funds. These funds are valued by the fund company based on the estimated fair value of the underlying fund holdings divided by the fund shares outstanding. Some hedge fund strategies utilize securities with readily available market prices, while others utilize less liquid investment vehicles that are valued based on unobservable inputs including cost, operating results, recent funding activity, or comparisons with similar investment vehicles. Venture capital fund investments are valued by the fund company based on estimated fair value of the underlying fund holdings divided by the fund shares outstanding. Some venture capital investments have progressed to the point that they have readily available exchange-based market valuations. Early stage venture investments are valued based on unobservable inputs including cost, operating results, discounted cash flows, the price of recent funding events, or pending offers from other viable entities. These private market investments furnish annual audited financial statements that are also used to further validate the information provided.

There were no material changes in valuation techniques or inputs during the years ended December 31, 2011 and 2010.

Employee Savings Plan

Idaho Power has a defined contribution plan designed to comply with Section 401(k) of the Internal Revenue Code and which covers substantially all employees (the Employee Savings Plan). Idaho Power matches specified percentages of employee contributions to the plan. Matching annual contributions were $6 million in 2011 and $5 million in both 2010 and 2009.

Post-employment Benefits

Idaho Power provides certain benefits to former or inactive employees, their beneficiaries, and covered dependents after employment but before retirement. These benefits include salary continuation, health care and life insurance for those employees found to be disabled under Idaho Power's disability plans, and health care for surviving spouses and dependents. Idaho Power accrues a liability for such benefits. The post employment benefit amounts included in other deferred credits on IDACORP's and Idaho Power's consolidated balance sheets at December 31, 2011 and 2010 are $3.8 million and $4.5 million, respectively.

12. PROPERTY, PLANT AND EQUIPMENT AND JOINTLY-OWNED PROJECTS

The following table presents the major classifications of Idaho Power's utility plant in service, annual depreciation provisions as a percent of average depreciable balance, and accumulated provision for depreciation for the years 2011 and 2010 (in thousands of dollars):

	2011		2010	
	Balance	**Avg Rate**	**Balance**	**Avg Rate**
Production	$ 1,832,287	2.22%	$ 1,792,305	2.23%
Transmission	871,784	2.06%	855,202	2.03%
Distribution	1,434,925	3.12%	1,377,239	3.13%
General and Other	327,877	7.32%	307,308	7.41%
Total in service	4,466,873	2.83%	4,332,054	2.84%
Accumulated provision for depreciation	(1,677,609)		(1,614,013)	
In service - net	$ 2,789,264		$ 2,718,041	

In 2010, Idaho Power sold $19 million of transmission-related assets to PacifiCorp at book value.

Idaho Power has interests in three jointly-owned generating facilities included in the table above. Under the joint operating agreements, each participating utility is responsible for financing its share of construction, operating, and leasing costs. Idaho Power's proportionate share of related fuel expenses as well as direct operation and maintenance expenses applicable to the projects is included in the Consolidated Statements of Income. These facilities, and the extent of Idaho Power's participation, were as follows at December 31, 2011 (in thousands of dollars):

Name of Plant	Location	Utility Plant in Service	Construction Work in Progress	Accumulated Provision for Depreciation	Ownership %	MW [(1)]
Jim Bridger Units 1-4	Rock Springs, WY	$ 539,294	$ 8,334	$ 276,375	33	771
Boardman	Boardman, OR	79,714	940	53,843	10	64
Valmy Units 1 and 2	Winnemucca, NV	350,582	7,352	202,811	50	284

[(1)] Idaho Power's share of nameplate capacity.

IERCo, Idaho Power's wholly-owned subsidiary, is a joint venturer in BCC. Idaho Power's coal purchases from the joint venture were $65 million, $76 million, and $66 million in 2011, 2010, and 2009, respectively.

Idaho Power has contracts to purchase the energy from four PURPA qualified facilities that are 50 percent owned by Ida-West. Idaho Power's power purchases from these facilities were $9 million, $8 million, and $9 million in 2011, 2010, and 2009, respectively.

See Note 1 for a discussion of the property of IDACORP's consolidated VIE.

13. ASSET RETIREMENT OBLIGATIONS (ARO)

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

Idaho Power's recorded AROs relate to the removal of polychlorinated biphenyls-contaminated equipment at its distribution facilities and the reclamation and removal costs at its jointly owned coal-fired generation facilities. In 2011, changes in estimates at its distribution facilities and at the coal-fired generation facilities resulted in a net increase of $3.9 million in the recorded AROs. The primary cause of the increase in the AROs was the decision to decommission the Boardman generating facility at December 31, 2020. A decommissioning study was performed, and now that a removal date has been determined and the fair value of the associated liabilities can be estimated, ARO amounts related to the Boardman decommissioning are being recognized in the consolidated financial statements.

Idaho Power also has additional AROs associated with its transmission system, hydroelectric facilities, and jointly owned coal-fired generation facilities; however, due to the indeterminate removal date, the fair value of the associated liabilities currently cannot be estimated and no amounts are recognized in the consolidated financial statements.

The regulated operations of Idaho Power also collect removal costs in rates for certain assets that do not have associated AROs. Idaho Power is required to redesignate these removal costs as regulatory liabilities. See Note 3 for the costs recorded as regulatory liabilities on IDACORP's and Idaho Power's Consolidated Balance Sheets as of December 31, 2011 and 2010.

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

		2011		**2010**
Balance at beginning of year	$	16,952	$	16,240
Accretion expense		936		819
Revisions in estimated cash flows		3,930		929
Liability settled		(451)		(1,036)
Balance at end of year	$	21,367	$	16,952

14. INVESTMENTS IN DEBT AND EQUITY SECURITIES

The table below summarizes IDACORP's and Idaho Power's investments as of December 31 (in thousands of dollars).

		2011		**2010**
Idaho Power investments:				
Equity method investment	$	102,158	$	90,495
Available-for-sale equity securities		22,205		24,561
Executive deferred compensation plan		3,439		4,746
Other investments		2		3
Total Idaho Power investments		127,804		119,805
Investments in affordable housing		62,556		73,583
Equity method investments		10,782		10,795
Executive deferred compensation plan		—		615
Total IDACORP investments	$	201,142	$	204,798

Equity Method Investments

Idaho Power, through its subsidiary IERCo, is a 33 percent owner of BCC. Ida-West, through separate subsidiaries, owns 50 percent of three electric generation projects that are accounted for using the equity method: South Forks Joint Venture; Hazelton/Wilson Joint Venture, and Snow Mountain Hydro LLC. IFS invests in affordable housing developments. All projects are reviewed periodically for impairment. The table below presents IDACORP's and Idaho Power's earnings (loss) of unconsolidated equity-method investments (in thousands of dollars).

	2011	2010	2009
Bridger Coal Company (Idaho Power)	$ 9,018	$ 11,281	$ 8,256
Ida-West projects	2,858	2,579	1,933
IFS affordable housing projects (excluding tax credits)	(11,078)	(10,852)	(11,222)
Total	$ 798	$ 3,008	$ (1,033)

Investments in Debt and Equity Securities

Investments in securities classified as available-for-sale securities are reported at fair value, using either specific identification or average cost to determine the cost for computing gains or losses. Any unrealized gains or losses on available-for-sale securities are included in other comprehensive income.

The table below summarizes investments in equity securities by IDACORP and Idaho Power as of December 31, 2011 and December 31, 2010 (in thousands of dollars).

	December 31, 2011			December 31, 2010		
	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value	Gross Unrealized Gain	Gross Unrealized Loss	Fair Value
Available-for-sale securities	$ 4,220	$ 1	$ 22,205	$ 4,876	$ —	$ 24,561

At the end of each reporting period, IDACORP and Idaho Power analyze securities in loss positions to determine whether they have experienced a decline in market value that is considered other-than-temporary. At December 31, 2011, one security was in an immaterial unrealized loss position. No other-than-temporary impairment was recognized for this security due to the limited severity and duration of the unrealized loss position. At December 31, 2010, no securities were in an unrealized loss position. There were no sales of available-for-sale securities during the year ended December 31, 2011, 2010, or 2009.

15. DERIVATIVE FINANCIAL INSTRUMENTS

Commodity Price Risk

Idaho Power is exposed to market risk relating to electricity, natural gas, and other fuel commodity prices, all of which are heavily influenced by supply and demand. Market risk may also be influenced by market participants' nonperformance of their contractual obligations and commitments, which affects the supply of or demand for the commodity. Idaho Power uses derivative instruments, such as physical and financial forward contracts, for both electricity and fuel to manage the risks relating to these commodity price exposures. The objective of Idaho Power's energy purchase and sale activity is to meet the demand of retail electric customers, maintain appropriate physical reserves to ensure reliability, and make economic use of temporary surpluses that may develop.

All commodity-related derivative instruments not meeting the normal purchases and normal sales exception to derivative accounting are recorded at fair value on the balance sheet. Because of Idaho Power's PCA mechanisms, unrealized gains and losses associated with the changes in fair value of these derivative instruments are recorded as regulatory assets or liabilities. With the exception of forward contracts for the purchase of natural gas for use at Idaho Power's natural gas generation facilities, Idaho Power's physical forward contracts qualify for the normal purchases and normal sales exception.

All of Idaho Power's derivative instruments have been entered into for the purpose of economically hedging forecasted purchases and sales, though none of these instruments have been designated as cash flow hedges under derivative accounting guidance. Idaho Power offsets fair value amounts recognized on its balance sheet related to derivative instruments executed with the same counterparty under the same master netting agreement.

Derivative Instruments Summary

The tables below presents the fair values and locations of derivative instruments not designated as hedging instruments recorded on the balance sheets at December 31, 2011 and 2010 (in thousands of dollars).

	Asset Derivatives		Liability Derivatives	
	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
December 31, 2011				
Current:				
Financial swaps	Other current assets	$ 4,361	Other current assets	$ 1,036
Financial swaps	Other current liabilities	1,526	Other current liabilities	4,755
Forward contracts	Other current assets	70	Other current liabilities	1,370
Long-term:				
Financial swaps	Other assets	359	Other liabilities	108
Total		$ 6,316		$ 7,269
December 31, 2010				
Current:				
Financial swaps	Other current assets	$ 930	Other current assets	$ 356
Financial swaps	Other current liabilities	2,440	Other current liabilities	4,172
Forward contracts			Other current liabilities	508
Long-term:				
Financial swaps	Other liabilities	100	Other liabilities	138
Total		$ 3,470		$ 5,174

The table below presents the gains and losses on derivatives not designated as hedging instruments for the year ended December 31, 2011 and 2010 (in thousands of dollars).

	Location of Gain/(Loss) on Derivatives Recognized in Income	Gain/(Loss) on Derivatives Recognized in Income[(1)]	
		2011	2010
Financial swaps	Off-system sales	$ 9,594	$ 4,499
Financial swaps	Purchased power	(7,124)	(12,240)
Financial swaps	Fuel expense	501	(101)
Financial swaps	Other operations and maintenance	425	—
Forward contracts	Fuel Expense	—	(721)

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

Settlement gains and losses on electricity swap contracts are recorded on the income statement in off-system sales or purchased power depending on the forecasted position being economically hedged by the derivative contract. Settlement gains and losses on both financial and physical contracts for natural gas are reflected in fuel expense. Settlement gains and losses on diesel derivatives are recorded in other operations and maintenance expense. See Note 16 for additional information concerning the determination of fair value for Idaho Power's assets and liabilities from price risk management activities.

Idaho Power had volumes of derivative commodity forward contracts and swaps outstanding at December 31, 2011 and 2010 set forth in the table below.

		December 31,	
Commodity	Units	2011	2010
Electricity purchases	MWh	225,600	347,400
Electricity sales	MWh	1,298,420	338,200
Natural gas purchases	MMBtu	7,928,311	647,900
Natural gas sales	MMBtu	352,129	—
Diesel purchases	Gallons	1,273,997	1,061,969

Credit Risk

At December 31, 2011, Idaho Power did not have material credit exposure from financial instruments, including derivatives. Idaho Power monitors credit risk exposure through reviews of counterparty credit quality, corporate-wide counterparty credit exposure, and corporate-wide counterparty concentration levels. Idaho Power manages these risks by establishing appropriate credit and concentration limits on transactions with counterparties and requiring contractual guarantees, cash deposits, or letters of credit from counterparties or their affiliates, as deemed necessary. Idaho Power's physical power contracts are under Western Systems Power Pool agreements, physical gas contracts are under North American Energy Standards Board contracts, and financial transactions are under International Swaps and Derivatives Association, Inc. contracts. These contracts all contain adequate assurance clauses requiring collateralization if a counterparty has debt that is downgraded below investment grade by at least one rating agency.

Credit-Contingent Features

Certain of Idaho Power's derivative instruments contain provisions that require Idaho Power's unsecured debt to maintain an investment grade credit rating from Moody's Investors Service and Standard & Poor's Ratings Services. If Idaho Power's unsecured debt were to fall below investment grade, it would be in violation of these provisions, and the counterparties to the derivative instruments could request immediate payment or demand immediate and ongoing full overnight collateralization on derivative instruments in net liability positions. The aggregate fair value of all derivative instruments with credit-risk-related contingent features that were in a liability position at December 31, 2011, was $7.0 million. Idaho Power posted no collateral related to this amount. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2011, Idaho Power would have been required to post $4.4 million of cash collateral to its counterparties.

16. FAIR VALUE MEASUREMENTS

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

Financial assets and liabilities recorded on the consolidated balance sheets are categorized based on the inputs to the valuation techniques as follows:

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

- Level 2: Financial assets and liabilities whose values are based on:
    a) quoted prices for similar assets or liabilities in active markets;
    b) quoted prices for identical or similar assets or liabilities in non-active markets;
    c) pricing models whose inputs are observable for substantially the full term of the asset or liability; and
    d) pricing models whose inputs are derived principally from or corroborated by observable market data through correlation or other means for substantially the full term of the asset or liability.

  IDACORP and Idaho Power Level 2 inputs are based on quoted market prices adjusted for location using corroborated, observable market data.

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

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

The table below presents information about IDACORP's and Idaho Power's assets and liabilities measured at fair value on a recurring basis as of December 31, 2011 and 2010 (in thousands of dollars). IDACORP's and Idaho Power's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy. There were no transfers between levels for the years presented.

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total
December 31, 2011				
IDACORP				
Assets:				
Derivatives	$ 3,654	$ 100	$ —	$ 3,754
Money market funds	100	—	—	100
Trading securities: Equity securities	3,439	—	—	3,439
Available-for-sale securities: Equity securities	22,205	—	—	22,205
Liabilities:				
Derivatives	$ 405	$ 4,302	$ —	$ 4,707
Idaho Power				
Assets:				
Derivatives	$ 3,654	$ 100	$ —	$ 3,754
Money market funds	100	—	—	100
Trading securities: Equity securities	3,439	—	—	3,439
Available-for-sale securities: Equity securities	22,205	—	—	22,205
Liabilities:				
Derivatives	$ 405	$ 4,302	$ —	$ 4,707
December 31, 2010				
IDACORP				
Assets:				
Derivatives	$ 573	$ —	$ —	$ 573
Money market funds	151,975	—	—	151,975
Trading securities: Equity securities	5,361	—	—	5,361
Available-for-sale securities: Equity securities	24,561	—	—	24,561
Liabilities:				
Derivatives	$ —	$ 508	$ —	$ 508
Idaho Power				
Assets:				
Derivatives	$ 573	$ —	$ —	$ 573
Money market funds	151,173	—	—	151,173
Trading securities: Equity securities	4,746	—	—	4,746
Available-for-sale securities: Equity securities	24,561	—	—	24,561
Liabilities:				
Derivatives	$ —	$ 508	$ —	$ 508

The table below presents the carrying value and estimated fair value of financial instruments that are not reported at fair value, as of December 31, 2011 and 2010, using available market information and appropriate valuation methodologies. The use of different market assumptions and/or estimation methodologies may have a material effect on the estimated fair value amounts. Cash and cash equivalents, deposits, customer and other receivables, notes payable, accounts payable, interest accrued, and taxes accrued are reported at their carrying value as these are a reasonable estimate of their fair value. The estimated fair values for notes receivable and long-term debt are based upon quoted market prices of the same or similar issues or discounted cash flow analysis as appropriate.

	December 31, 2011		December 31, 2010	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	(thousands of dollars)			
IDACORP				
Assets:				
Notes receivable	$ 3,097	$ 3,097	$ 2,946	$ 2,946
Liabilities:				
Long-term debt	1,491,727	1,737,912	1,614,299	1,622,924
Idaho Power				
Liabilities:				
Long-term debt	$ 1,491,727	$ 1,737,912	$ 1,612,790	$ 1,621,425

17. SEGMENT INFORMATION

IDACORP's only reportable segment is utility operations. The utility operations segment's primary source of revenue is the regulated operations of Idaho Power. Idaho Power's regulated operations include the generation, transmission, distribution, purchase, and sale of electricity. This segment also includes income from IERCo, a wholly-owned subsidiary of Idaho Power that is also subject to regulation and is a thirty-three percent owner of BCC, an unconsolidated joint venture.

IDACORP's other operating segments are below the quantitative and qualitative thresholds for reportable segments and are included in the "All Other" category in the table below. This category is comprised of IFS's investments in affordable housing developments and historic rehabilitation projects, Ida-West's joint venture investments in small hydroelectric generation projects, the remaining activities of energy marketer IE, which wound down its operations in 2003, and IDACORP's holding company expenses.

The table below summarizes the segment information for IDACORP's utility operations and the total of all other segments, and reconciles this information to total enterprise amounts (in thousands of dollars).

	Utility Operations	All Other	Eliminations	Consolidated Total
2011				
Revenues	$ 1,022,728	$ 4,028	$ —	$ 1,026,756
Operating income (loss)	164,366	(118)	—	164,248
Other income	18,876	30	—	18,906
Interest income	2,146	233	(76)	2,303
Equity method income (loss)	9,018	(8,220)	—	798
Interest expense	71,055	547	(76)	71,526
Income (loss) before income taxes	123,351	(8,622)	—	114,729
Income tax benefit	(41,399)	(10,734)	—	(52,133)
Income attributable to IDACORP, Inc.	164,750	1,943	—	166,693
Total assets	4,856,839	122,678	(18,908)	4,960,609
Expenditures for long-lived assets	337,765	5	—	337,770
2010				
Revenues	$ 1,033,052	$ 2,977	$ —	$ 1,036,029
Operating income (loss)	200,308	(1,638)	—	198,670
Other income	11,567	558	—	12,125
Interest income	2,116	1,023	(99)	3,040
Equity method income (loss)	11,281	(8,273)	—	3,008
Interest expense	73,925	1,288	(99)	75,114
Income (loss) before income taxes	151,347	(9,618)	—	141,729
Income tax expense (benefit)	10,713	(11,444)	—	(731)
Income attributable to IDACORP, Inc.	140,634	2,164	—	142,798
Total assets	4,568,393	131,553	(23,891)	4,676,055
Expenditures for long-lived assets	338,252	—	—	338,252
2009				
Revenues	$ 1,045,996	$ 3,804	$ —	$ 1,049,800
Operating income (loss)	206,193	(2,610)	—	203,583
Other income	10,704	1,227	—	11,931
Interest income	4,859	490	(283)	5,066
Equity method income (loss)	8,256	(9,289)	—	(1,033)
Interest expense	71,932	1,161	(283)	72,810
Income (loss) before income taxes	158,080	(11,343)	—	146,737
Income tax expense (benefit)	35,521	(13,159)	—	22,362
Income attributable to IDACORP, Inc.	122,559	1,791	—	124,350
Total assets	4,073,390	192,699	(27,362)	4,238,727
Expenditures for long-lived assets	251,937	14	—	251,951

18. OTHER INCOME AND EXPENSE

The following table presents the components of IDACORP's other income, net (in thousands of dollars):

	2011	2010	2009
Allowance for funds used during construction-equity	$ 25,484	$ 16,551	$ 7,555
Investment income, net	2,305	3,046	5,071
Carrying charges on regulatory assets	1,665	921	4,471
Other income	107	2,199	3,967
SMSP expense	(6,579)	(5,709)	(5,355)
Life insurance proceeds, net of premiums	757	(93)	4,197
Other expense	(2,530)	(1,750)	(2,909)
Other income, net	$ 21,209	$ 15,165	$ 16,997

19. RELATED PARTY TRANSACTIONS

IDACORP: Idaho Power performs corporate functions such as financial, legal, and management services for IDACORP and its subsidiaries. Idaho Power charges IDACORP for the costs of these services based on service agreements and other specifically identified costs. For these services Idaho Power billed IDACORP $0.8 million, $0.8 million, and $0.9 million in 2011, 2010, and 2009, respectively.

Ida-West: Idaho Power purchases all of the power generated by four of Ida-West's hydroelectric projects located in Idaho. Idaho Power paid $9 million, $8 million, and $9 million to Ida-West in 2011, 2010, and 2009, respectively.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
IDACORP, Inc.
Boise, Idaho

We have audited the accompanying consolidated balance sheets of IDACORP, Inc. and subsidiaries (the "Company") as of December 31, 2011 and 2010, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2011. Our audits also included the financial statement schedules listed in the Index at Item 8. These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedules based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of IDACORP, Inc. and subsidiaries at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2011, based on the criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 22, 2012 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ *DELOITTE & TOUCHE LLP*

Boise, Idaho
February 22, 2012

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Idaho Power Company
Boise, Idaho

We have audited the accompanying consolidated balance sheets and statements of capitalization of Idaho Power Company and subsidiary (the "Company") as of December 31, 2011 and 2010, and the related consolidated statements of income, comprehensive income, retained earnings, and cash flows for each of the three years in the period ended December 31, 2011. Our audits also included the financial statement schedule listed in the Index at Item 8. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Idaho Power Company and subsidiary at December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2011, based on the criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 22, 2012 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ *DELOITTE & TOUCHE LLP*

Boise, Idaho
February 22, 2012

SUPPLEMENTAL FINANCIAL INFORMATION, UNAUDITED

QUARTERLY FINANCIAL DATA

The following unaudited information is presented for each quarter of 2011 and 2010 (in thousands of dollars, except for per share amounts). In the opinion of each company, all adjustments necessary for a fair statement of such amounts for such periods have been included. The results of operations for the interim periods are not necessarily indicative of the results to be expected for the full year. Accordingly, earnings information for any three-month period should not be considered as a basis for estimating operating results for a full fiscal year. Amounts are based upon quarterly statements and the sum of the quarters may not equal the annual amount reported.

	Quarter Ended			
	March 31	**June 30**	**September 30**	**December 31**
IDACORP, Inc.				
2011				
Revenues	$ 251,494	$ 234,983	$ 309,630	$ 230,648
Operating income	50,091	34,299	71,393	8,464
Net income	29,488	20,977	107,414	8,983
Net income attributable to IDACORP, Inc.	29,740	20,901	107,067	8,985
Basic earnings per share	0.60	0.42	2.16	0.18
Diluted earnings per share	0.60	0.42	2.16	0.18
2010				
Revenues	$ 252,963	$ 241,753	$ 309,357	$ 231,956
Operating income	34,047	36,605	88,993	39,025
Net income	15,857	39,237	67,125	20,241
Net income attributable to IDACORP, Inc.	16,063	39,209	67,135	20,391
Basic earnings per share	0.34	0.82	1.40	0.41
Diluted earnings per share	0.34	0.82	1.39	0.41
Idaho Power Company				
2011				
Revenues	$ 251,062	$ 233,924	$ 308,045	$ 229,697
Income from operations	50,713	34,153	70,415	9,086
Net income	29,848	20,701	104,872	9,330
2010				
Revenues	$ 252,460	$ 240,790	$ 308,468	$ 231,333
Income from operations	34,384	36,391	89,566	39,966
Net income	18,221	38,828	64,650	18,935

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures - IDACORP, Inc.

The Chief Executive Officer and Chief Financial Officer of IDACORP, Inc., based on their evaluation of IDACORP, Inc.'s disclosure controls and procedures (as defined in Exchange Act Rule 13a-15(e)) as of December 31, 2011, have concluded that IDACORP, Inc.'s disclosure controls and procedures are effective as of that date.

Internal Control Over Financial Reporting - IDACORP, Inc.

Management's Annual Report on Internal Control Over Financial Reporting

The management of IDACORP is responsible for establishing and maintaining adequate internal control over financial reporting for IDACORP. Internal control over financial reporting is defined in Rule 13a-15(f) promulgated under the Securities Exchange Act of 1934 as a process designed by, or under the supervision of, the company's principal executive and principal financial officers and effected by the company's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America and includes those policies and procedures that:

- pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the company;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures of the company are being made only in accordance with the authorizations of management and directors of the company; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

IDACORP's management assessed the effectiveness of the company's internal control over financial reporting as of December 31, 2011. In making this assessment, the company's management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control-Integrated Framework.*

Based on its assessment, management concluded that, as of December 31, 2011, IDACORP's internal control over financial reporting is effective based on those criteria.

IDACORP's independent registered public accounting firm has audited the financial statements included in this Annual Report on Form 10-K for the year ended December 31, 2011 and issued a report, which appears on the next page and expresses an unqualified opinion on the effectiveness of IDACORP's internal control over financial reporting as of December 31, 2011.

February 22, 2012

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
IDACORP, Inc.
Boise, Idaho

We have audited the internal control over financial reporting of IDACORP, Inc. and subsidiaries (the "Company") as of December 31, 2011, based on the criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Annual Report on Internal Control over Financial Reporting.* Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2011 of the Company and our report dated February 22, 2012 expressed an unqualified opinion on those financial statements and financial statement schedules.

/s/ *DELOITTE & TOUCHE LLP*

Boise, Idaho
February 22, 2012

Disclosure Controls and Procedures - Idaho Power Company

The Chief Executive Officer and Chief Financial Officer of Idaho Power Company, based on their evaluation of Idaho Power Company's disclosure controls and procedures (as defined in Exchange Act Rule 13a-15(e)) as of December 31, 2011, have concluded that Idaho Power Company's disclosure controls and procedures are effective as of that date.

Internal Control Over Financial Reporting - Idaho Power Company

Management's Annual Report on Internal Control Over Financial Reporting

The management of Idaho Power Company (Idaho Power) is responsible for establishing and maintaining adequate internal control over financial reporting of Idaho Power. Internal control over financial reporting is defined in Rule 13a-15(f) promulgated under the Securities Exchange Act of 1934 as a process designed by, or under the supervision of, the company's principal executive and principal financial officers and effected by the company's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America and includes those policies and procedures that:

- pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the company;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures of the company are being made only in accordance with the authorizations of management and directors of the company; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Idaho Power's management assessed the effectiveness of the company's internal control over financial reporting as of December 31, 2011. In making this assessment, the company's management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control-Integrated Framework.*

Based on its assessment, management concluded that, as of December 31, 2011, Idaho Power's internal control over financial reporting is effective based on those criteria.

Idaho Power's independent registered public accounting firm has audited the financial statements included in this Annual Report on Form 10-K for the year ended December 31, 2011 and issued a report which appears on the next page and expresses an unqualified opinion on the effectiveness of Idaho Power's internal control over financial reporting as of December 31, 2011.

February 22, 2012

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Idaho Power Company
Boise, Idaho

We have audited the internal control over financial reporting of Idaho Power Company and subsidiary (the "Company") as of December 31, 2011, based on the criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Annual Report on Internal Control over Financial Reporting.* Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the criteria established in *Internal Control-Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2011 of the Company and our report dated February 22, 2012 expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/ *DELOITTE & TOUCHE LLP*

Boise, Idaho
February 22, 2012

Changes in Internal Control Over Financial Reporting - IDACORP, Inc. and Idaho Power Company

There have been no changes in IDACORP, Inc.'s or Idaho Power Company's internal control over financial reporting during the quarter ended December 31, 2011 that have materially affected, or are reasonably likely to materially affect, IDACORP, Inc.'s or Idaho Power Company's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS, AND CORPORATE GOVERNANCE

The portions of IDACORP's definitive proxy statement appearing under the captions "Proposal No. 1: Election of Directors - Nominees for Election - Terms Expire 2015," "Continuing Directors – Terms Expire 2014," "Continuing Directors - Terms Expire 2013," "Section 16(a) Beneficial Ownership Reporting Compliance," "Corporate Governance - Audit Committee," and "Corporate Governance - Code of Ethics," to be filed pursuant to Regulation 14A for the 2012 annual meeting of shareholders are hereby incorporated by reference.

Information regarding IDACORP's executive officers required by this item appears in Item 1 of this report under "Executive Officers of the Registrants."

ITEM 11. EXECUTIVE COMPENSATION

The portion of IDACORP's definitive proxy statement appearing under the caption "Executive Compensation" to be filed pursuant to Regulation 14A for the 2012 annual meeting of shareholders is hereby incorporated by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The portion of IDACORP's definitive proxy statement appearing under the caption "Security Ownership of Directors, Executive Officers and Five Percent Shareholders" to be filed pursuant to Regulation 14A for the 2012 annual meeting of shareholders is hereby incorporated by reference.

The following table includes information as of December 31, 2011 with respect to equity compensation plans where equity securities of IDACORP may be issued. These plans are the 1994 Restricted Stock Plan (RSP) and the IDACORP 2000 Long-Term Incentive and Compensation Plan (LTICP).

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by shareholders [1]	27,806	$ 32.29	1,519,657 [2]
Equity compensation plans not approved by shareholders	—	$ —	—
Total	27,806	$ 32.29	1,519,657

(1) Consists of the RSP and the LTICP.

(2) In addition to being available for future issuance upon exercise of options, 1,503,861 shares under the LTICP may instead be issued in connection with stock appreciation rights, restricted stock, restricted stock units, performance units, performance shares, or other equity-based awards as of December 31, 2011. 15,796 shares remain available for future issuance under the RSP.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The portions of IDACORP's definitive proxy statement appearing under the captions "Related Person Transaction Disclosure" and "Corporate Governance – Director Independence" to be filed pursuant to Regulation 14A for the 2012 annual meeting of shareholders are hereby incorporated by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

IDACORP: The portion of IDACORP's definitive proxy statement appearing under the caption "Independent Accountant Billings" in the proxy statement to be filed pursuant to Regulation 14A for the 2012 annual meeting of shareholders is hereby incorporated by reference.

Idaho Power: The table below presents the aggregate fees our principal independent registered public accounting firm, Deloitte & Touche LLP, billed or are expected to bill to Idaho Power for the fiscal years ended December 31, 2011 and 2010:

	2011	2010
Audit fees	$ 1,047,708	$ 1,003,947
Audit-related fees[(1)]	91,700	65,930
Tax fee[(2)]	87,648	259,423
All other fees[(3)]	2,200	2,200
Total	$ 1,229,256	$ 1,331,500

[(1)] Audits of Idaho Power's benefit plans and compliance audit for the U.S. DOE Smart Grid grant.

[(2)] Includes fees for benefit plan tax returns and consultation related to tax accounting method changes.

[(3)] Accounting research tool subscription.

Policy on Audit Committee Pre-Approval:

Idaho Power and the Audit Committee are committed to ensuring the independence of the independent registered public accounting firm, both in fact and in appearance. In this regard, the Audit Committee has established and periodically reviews a pre-approval policy for audit and non-audit services. For 2010 and 2011, all audit and non-audit services and all fees paid in connection with those services were pre-approved by the Audit Committee.

In addition to the audits of Idaho Power's consolidated financial statements, the independent public accounting firm may be engaged to provide certain audit-related, tax, and other services. The Audit Committee must pre-approve all services performed by the independent public accounting firm to assure that the provision of those services does not impair the public accounting firm's independence. The services that the Audit Committee will consider include: audit services such as attest services, changes in the scope of the audit of the financial statements, and the issuance of comfort letters and consents in connection with financings; audit-related services such as internal control reviews and assistance with internal control reporting requirements; attest services related to financial reporting that are not required by statute or regulation, and accounting consultations and audits related to proposed transactions and new or proposed accounting rules, standards and interpretations; and tax compliance and planning services. Unless a type of service to be provided by the independent public accounting firm has received general pre-approval, it will require specific pre-approval by the Audit Committee. In addition, any proposed services exceeding pre-approved cost levels will require specific pre-approval by the Audit Committee. Under the pre-approval policy, the Audit Committee has delegated to the Chairman of the Audit Committee pre-approval authority for proposed services; however, the Chairman must report any pre-approval decisions to the Audit Committee at its next scheduled meeting.

Any request to engage the independent public accounting firm to provide a service which has not received general pre-approval must be submitted as a written proposal to Idaho Power's Chief Financial Officer with a copy to the General Counsel. The request must include a detailed description of the service to be provided, the proposed fee, and the business reasons for engaging the independent public accounting firm to provide the service. Upon approval by the Chief Financial Officer, the General Counsel, and the independent public accounting firm that the proposed engagement complies with the terms of the pre-approval policy and the applicable rules and regulations, the request will be presented to the Audit Committee or the Committee Chairman, as the case may be, for pre-approval.

In determining whether to pre-approve the engagement of the independent public accounting firm, the Audit Committee or the Committee Chairman, as the case may be, must consider, among other things, the pre-approval policy, applicable rules and regulations, and whether the nature of the engagement and the related fees are consistent with the following principles:

- the independent public accounting firm cannot function in the role of management of Idaho Power; and
- the independent public accounting firm cannot audit its own work.

The pre-approval policy and separate supplements to the pre-approval policy describe the specific audit, audit related, tax, and other services that have the general pre-approval of the Audit Committee. The term of any pre-approval is 12 months from the date of pre-approval, unless the Audit Committee specifically provides for a different period. The Audit Committee will periodically revise the list of pre-approved services, based on subsequent determinations.

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(1) and (2) Please refer to Part II, Item 8 - "Financial Statements and Supplementary Data" for a complete listing of all consolidated financial statements and financial statement schedules.

(3) Exhibits.

The agreements filed as exhibits to this Annual Report on Form 10-K are filed to provide information regarding their terms and are not intended to provide any other factual or disclosure information about IDACORP, Inc., Idaho Power Company, or the other parties to the agreements. Some of the agreements contain representations and warranties by each of the parties to the applicable agreement. These representations and warranties have been made solely for the benefit of the other parties to the applicable agreement and (a) should not in all instances be treated as categorical statements of fact, but rather as a way of allocating the risk to one of the parties to the agreement if those statements prove to be inaccurate; (b) have been qualified by disclosures that were made to the other party, which disclosures are not necessarily reflected in the agreement; (c) may apply standards of materiality in a way that is different from what may be viewed as material to investors; and (d) were made only as of the date of the applicable agreement or such other date or dates as may be specified in the agreement and are subject to more recent developments.

* Previously filed and incorporated herein by reference

Exhibit No.	Description
*2	Agreement and Plan of Exchange between IDACORP, Inc., and Idaho Power Company dated as of February 2, 1998. File number 333-48031, Form S-4, filed on 3/16/98, as Exhibit A.
*3.1	Restated Articles of Incorporation of Idaho Power Company as filed with the Secretary of State of Idaho on June 30, 1989. File number 33-00440, Post-Effective Amendment No. 2 to Form S-3, filed on 6/30/89, as Exhibit 4(a)(xiii).
*3.2	Statement of Resolution Establishing Terms of Flexible Auction Series A, Serial Preferred Stock, Without Par Value (cumulative stated value of $100,000 per share) of Idaho Power Company, as filed with the Secretary of State of Idaho on November 5, 1991. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 4(a)(ii).
*3.3	Statement of Resolution Establishing Terms of 7.07% Serial Preferred Stock, Without Par Value (cumulative stated value of $100 per share) of Idaho Power Company, as filed with the Secretary of State of Idaho on June 30, 1993. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 4(a)(iii).
*3.4	Articles of Amendment to Restated Articles of Incorporation of Idaho Power Company, as filed with the Secretary of State of Idaho on June 15, 2000. File number 1-3198, Form 10-Q for the quarter ended June 30, 2000, filed on 8/4/00, as Exhibit 3(a)(iii).
*3.5	Articles of Amendment to Restated Articles of Incorporation of Idaho Power Company, as filed with the Secretary of State of Idaho on January 21, 2005. File number 1-3198, Form 8-K, filed on 1/26/05, as Exhibit 3.3.
*3.6	Articles of Amendment to Restated Articles of Incorporation of Idaho Power Company, as amended, as filed with the Secretary of State of Idaho on November 19, 2007. File number 1-3198, Form 8-K, filed on 11/19/07, as Exhibit 3.3.

Exhibit No.	Description
*3.7	Articles of Share Exchange, as filed with the Secretary of State of Idaho on September 29, 1998. File number 33-56071-99, Post-Effective Amendment No. 1 to Form S-8, filed on 10/1/98, as Exhibit 3(d).
*3.8	Amended Bylaws of Idaho Power Company, amended on November 15, 2007 and presently in effect. File number 1-3198, Form 8-K, filed on 11/19/07, as Exhibit 3.2.
*3.9	Articles of Incorporation of IDACORP, Inc. File number 333-64737, Amendment No. 1 to Form S-3, filed on 11/4/98, as Exhibit 3.1.
*3.10	Articles of Amendment to Articles of Incorporation of IDACORP, Inc. as filed with the Secretary of State of Idaho on March 9, 1998. File number 333-64737, Amendment No. 1 to Form S-3, filed on 11/4/98, as Exhibit 3.2.
*3.11	Articles of Amendment to Articles of Incorporation of IDACORP, Inc. creating A Series Preferred Stock, without par value, as filed with the Secretary of State of Idaho on September 17, 1998. File number 333-00139-99, Post-Effective Amendment No. 1 to Form S-3, filed on 9/22/98, as Exhibit 3(b).
*3.12	Amended Bylaws of IDACORP, Inc., amended on November 15, 2007 and presently in effect. File number 1-14456, Form 8-K, filed on 11/19/07, as Exhibit 3.1.
*4.1	Mortgage and Deed of Trust, dated as of October 1, 1937, between Idaho Power Company and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company) and R. G. Page, as Trustees. File number 2-3413, as Exhibit B-2.
*4.2	Idaho Power Company Supplemental Indentures to Mortgage and Deed of Trust: File number 1-MD, as Exhibit B-2-a, First, July 1, 1939 File number 2-5395, as Exhibit 7-a-3, Second, November 15, 1943 File number 2-7237, as Exhibit 7-a-4, Third, February 1, 1947 File number 2-7502, as Exhibit 7-a-5, Fourth, May 1, 1948 File number 2-8398, as Exhibit 7-a-6, Fifth, November 1, 1949 File number 2-8973, as Exhibit 7-a-7, Sixth, October 1, 1951 File number 2-12941, as Exhibit 2-C-8, Seventh, January 1, 1957 File number 2-13688, as Exhibit 4-J, Eighth, July 15, 1957 File number 2-13689, as Exhibit 4-K, Ninth, November 15, 1957 File number 2-14245, as Exhibit 4-L, Tenth, April 1, 1958 File number 2-14366, as Exhibit 2-L, Eleventh, October 15, 1958 File number 2-14935, as Exhibit 4-N, Twelfth, May 15, 1959 File number 2-18976, as Exhibit 4-O, Thirteenth, November 15, 1960 File number 2-18977, as Exhibit 4-Q, Fourteenth, November 1, 1961 File number 2-22988, as Exhibit 4-B-16, Fifteenth, September 15, 1964 File number 2-24578, as Exhibit 4-B-17, Sixteenth, April 1, 1966 File number 2-25479, as Exhibit 4-B-18, Seventeenth, October 1, 1966 File number 2-45260, as Exhibit 2(c), Eighteenth, September 1, 1972 File number 2-49854, as Exhibit 2(c), Nineteenth, January 15, 1974 File number 2-51722, as Exhibit 2(c)(i), Twentieth, August 1, 1974 File number 2-51722, as Exhibit 2(c)(ii), Twenty-first, October 15, 1974 File number 2-57374, as Exhibit 2(c), Twenty-second, November 15, 1976 File number 2-62035, as Exhibit 2(c), Twenty-third, August 15, 1978 File number 33-34222, as Exhibit 4(d)(iii), Twenty-fourth, September 1, 1979 File number 33-34222, as Exhibit 4(d)(iv), Twenty-fifth, November 1, 1981 File number 33-34222, as Exhibit 4(d)(v), Twenty-sixth, May 1, 1982 File number 33-34222, as Exhibit 4(d)(vi), Twenty-seventh, May 1, 1986 File number 33-00440, as Exhibit 4(c)(iv), Twenty-eighth, June 30, 1989 File number 33-34222, as Exhibit 4(d)(vii), Twenty-ninth, January 1, 1990 File number 33-65720, as Exhibit 4(d)(iii), Thirtieth, January 1, 1991 File number 33-65720, as Exhibit 4(d)(iv), Thirty-first, August 15, 1991 File number 33-65720, as Exhibit 4(d)(v), Thirty-second, March 15, 1992 File number 33-65720, as Exhibit 4(d)(vi), Thirty-third, April 1, 1993

Exhibit No.	Description
	File number 1-3198, Form 8-K, filed on 12/20/93, as Exhibit 4, Thirty-fourth, December 1, 1993 File number 1-3198, Form 8-K, filed on 11/21/00, as Exhibit 4, Thirty-fifth, November 1, 2000 File number 1-3198, Form 8-K, filed on 10/1/01, as Exhibit 4, Thirty-sixth, October 1, 2001 File number 1-3198, Form 8-K, filed on 4/16/03, as Exhibit 4, Thirty-seventh, April 1, 2003 File number 1-3198, Form 10-Q for the quarter ended June 30, 2003, filed on 8/7/03, as Exhibit 4(a)(iii), Thirty-eighth, May 15, 2003 File number 1-3198, Form 10-Q for the quarter ended September 30, 2003, filed on 11/6/03, as Exhibit 4(a)(iv), Thirty-ninth, October 1, 2003 File number 1-3198, Form 8-K filed on 5/10/05, as Exhibit 4, Fortieth, May 1, 2005 File number 1-3198, Form 8-K filed on 10/10/06, as Exhibit 4, Forty-first, October 1, 2006 File number 1-3198, Form 8-K filed on 6/4/07, as Exhibit 4, Forty-second, May 1, 2007 File number 1-3198, Form 8-K filed on 9/26/07, as Exhibit 4, Forty-third, September 1, 2007 File number 1-3198, Form 8-K filed on 4/3/08, as Exhibit 4, Forty-fourth, April 1, 2008 File number 1-3198, Form 10-K filed on 2/23/10, as Exhibit 4.10, Forty-fifth, February 1, 2010 File number 1-3198, Form 8-K filed on 6/18/10, as Exhibit 4, Forty-sixth, June 1, 2010
*4.3	Instruments relating to Idaho Power Company American Falls bond guarantee (see Exhibit 10.4). File number 1-3198, Form 10-Q for the quarter ended June 30, 2000, filed on 8/4/00, as Exhibit 4(b).
*4.4	Agreement of Idaho Power Company to furnish certain debt instruments. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 4(f).
*4.5	Agreement of IDACORP, Inc. to furnish certain debt instruments. File number 1-14465, Form 10-Q for the quarter ended September 30, 2003, filed on 11/6/03, as Exhibit 4(c)(ii).
*4.6	Agreement and Plan of Merger dated March 10, 1989, between Idaho Power Company, a Maine Corporation, and Idaho Power Migrating Corporation. File number 33-00440, Post-Effective Amendment No. 2 to Form S-3, filed on 6/30/89, as Exhibit 2(a)(iii).
*4.7	Indenture for Senior Debt Securities dated as of February 1, 2001, between IDACORP, Inc. and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), as trustee. File number 1-14465, Form 8-K, filed on 2/28/01, as Exhibit 4.1.
*4.8	First Supplemental Indenture dated as of February 1, 2001 to Indenture for Senior Debt Securities dated as of February 1, 2001 between IDACORP, Inc. and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), as trustee. File number 1-14465, Form 8-K, filed on 2/28/01, as Exhibit 4.2.
*4.9	Indenture for Debt Securities dated as of August 1, 2001 between Idaho Power Company and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), as trustee. File number 333-67748, Form S-3, filed on 8/16/01, as Exhibit 4.13.
*4.10	Idaho Power Company Instrument of Further Assurance relating to Mortgage and Deed of Trust, dated as of August 3, 2010. File number 1-3198, Form 10-Q for the quarter ended June 30, 2010, filed on 8/5/10, as Exhibit 4.12.
*10.1	Agreements, dated September 22, 1969, between Idaho Power Company and Pacific Power & Light Company, relating to the operation, construction, and ownership of the Jim Bridger Project. File number 2-49584, as Exhibit 5(b).
*10.2	Amendment, dated February 1, 1974, relating to the operation agreement filed as Exhibit 10.1. File number 2-51762, as Exhibit 5(c).
*10.3	Agreement, dated as of October 11, 1973, between Idaho Power Company and Pacific Power & Light Company. File number 2-49584, as Exhibit 5(c).
*10.4	Guaranty Agreement, dated April 11, 2000, between Idaho Power Company and Bank One Trust Company, N.A., as Trustee, relating to $19,885,000 American Falls Replacement Dam Refinancing Bonds of the American Falls Reservoir District, Idaho. File number 1-3198, Form 10-Q for the quarter ended June 30, 2000, filed on 8/4/00, as Exhibit 10(c).
*10.5	Guaranty Agreement, dated as of August 30, 1974, between Idaho Power Company and Pacific Power & Light Company. File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(r).

Exhibit No.	Description
*10.6	Letter Agreement, dated January 23, 1976, between Idaho Power Company and Portland General Electric Company. File number 2-56513, as Exhibit 5(i).
*10.7	Agreement for Construction, Ownership and Operation of the Number One Boardman Station on Carty Reservoir, dated as of October 15, 1976, between Portland General Electric Company and Idaho Power Company. File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(s).
*10.8	Amendment, dated September 30, 1977, relating to agreement filed as Exhibit 10.6. File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(t).
*10.9	Amendment, dated October 31, 1977, relating to agreement filed as Exhibit 10.6. File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(u).
*10.10	Amendment, dated January 23, 1978, relating to agreement filed as Exhibit 10.6. File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(v).
*10.11	Amendment, dated February 15, 1978, relating to agreement filed as Exhibit 10.6. File number 2-62034, Form S-7, filed on 6/30/78, as Exhibit 5(w).
*10.12	Amendment, dated September 1, 1979, relating to agreement filed as Exhibit 10.6. File number 2-68574, Form S-7, filed on 7/23/80, as Exhibit 5(x).
*10.13	Participation Agreement, dated September 1, 1979, relating to the sale and leaseback of coal handling facilities at the Number One Boardman Station on Carty Reservoir. File number 2-68574, Form S-7, filed on 7/23/80, as Exhibit 5(z).
*10.14	Agreements for the Operation, Construction and Ownership of the North Valmy Power Plant Project, dated December 12, 1978, between Sierra Pacific Power Company and Idaho Power Company. File number 2-64910, Form S-7, filed on 6/29/79, as Exhibit 5(y).
*10.15	Framework Agreement, dated October 1, 1984, between the State of Idaho and Idaho Power Company relating to Idaho Power Company's Swan Falls and Snake River water rights. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 10(h).
*10.16	Agreement, dated October 25, 1984, between the State of Idaho and Idaho Power Company, relating to the agreement filed as Exhibit 10.15. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 10(h)(i).
*10.17	Settlement Agreement, dated March 25, 2009, between the State of Idaho and Idaho Power Company relating to the agreement filed as Exhibit 10.15. File number 1-14465, 1-3198, Form 10-Q for the quarter ended March 31, 2009, filed on 5/7/09, as Exhibit 10.58.
*10.18	Contract to Implement, dated October 25, 1984, between the State of Idaho and Idaho Power Company, relating to the agreement filed as Exhibit 10.15. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 10(h)(ii).
*10.19	Agreement Regarding the Ownership, Construction, Operation and Maintenance of the Milner Hydroelectric Project (FERC No. 2899), dated January 22, 1990, between Idaho Power Company and the Twin Falls Canal Company and the Northside Canal Company Limited. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 10(m).
*10.20[1]	Idaho Power Company Security Plan for Senior Management Employees I, amended and restated effective December 31, 2004, and as further amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.15.
10.21[1]	Idaho Power Company Security Plan for Senior Management Employees II, effective January 1, 2005, as amended and restated November 30, 2011.
*10.22[1]	IDACORP, Inc. Restricted Stock Plan, as amended and restated September 20, 2007. File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2007, filed on 10/31/07, as Exhibit 10(h)(iii).
*10.23[1]	IDACORP, Inc. Restricted Stock Plan - Form of Restricted Stock Agreement (time-vesting) (July 20, 2006). File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(vi).

Exhibit No.	Description
*10.24[1]	IDACORP, Inc. Restricted Stock Plan - Form of Performance Stock Agreement (performance vesting) (July 20, 2006). File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(vii).
*10.25[1]	Idaho Power Company Security Plan for Board of Directors - a non-qualified deferred compensation plan, as amended and restated effective July 20, 2006. File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(viii).
10.26[1]	IDACORP, Inc. Non-Employee Directors Stock Compensation Plan, as amended January 19, 2012.
*10.27[1]	Form of Officer Indemnification Agreement between IDACORP, Inc. and Officers of IDACORP, Inc. and Idaho Power Company, as amended July 20, 2006. File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(xix).
*10.28[1]	Form of Director Indemnification Agreement between IDACORP, Inc. and Directors of IDACORP, Inc., as amended July 20, 2006. File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(xx).
*10.29[1]	Form of Amended and Restated Change in Control Agreement between IDACORP, Inc. and Officers of IDACORP and Idaho Power Company (senior vice president and higher), approved November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.24.
*10.30[1]	Form of Amended and Restated Change in Control Agreement between IDACORP, Inc. and Officers of IDACORP and Idaho Power Company (below senior vice president), approved November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.25.
*10.31[1]	Form of Amended and Restated Change in Control Agreement between IDACORP, Inc. and Officers of IDACORP, Inc. and Idaho Power Company, approved March 17, 2010. File number 1-14465, 1-3198, Form 8-K, filed on 3/24/10, as Exhibit 10.1.
10.32[1]	IDACORP, Inc. and/or Idaho Power Company Executive Officers with Amended and Restated Change in Control Agreements chart, as of January 1, 2012.
*10.33[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan, as amended November 18, 2010.
*10.34[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Stock Option Award Agreement (July 20, 2006). File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(xvi).
*10.35[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Restricted Stock Award Agreement (time vesting) (July 20, 2006). File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(xvii).
*10.36[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Restricted Stock Award Agreement (performance vesting) (July 20, 2006). File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2006, filed on 11/2/06, as Exhibit 10(h)(xviii).
*10.37[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Performance Share Award Agreement (performance with two goals) (November 20, 2008). File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.30.
*10.38[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Performance Share Award Agreement (performance with two goals) (February 25, 2011). File number 1-14465, 1-3198, Form 10-Q for the quarter ended March 31, 2011, filed on 5/5/11, as Exhibit 10.69.
*10.39[1]	IDACORP, Inc. Executive Incentive Plan, as amended March 18, 2010 and approved May 20, 2010. File number 1-14465, 1-3198, Form 8-K, filed on 5/21/10, as Exhibit 10.1.
*10.40[1]	Idaho Power Company Executive Deferred Compensation Plan, effective November 15, 2000, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.32.

Exhibit No.	Description
*10.41[1]	IDACORP, Inc. and Idaho Power Company Compensation for Non-Employee Directors of the Board of Directors, as amended January 21, 2010. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2009, filed on 2/23/10, as Exhibit 10.33.
*10.42[1]	Form of IDACORP, Inc. Director Deferred Compensation Agreement, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.46.
*10.43[1]	Form of Letter Agreement to Amend Outstanding IDACORP, Inc. Director Deferred Compensation Agreement (November 16, 2008). File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.47.
*10.44[1]	Form of Amendment to IDACORP, Inc. Director Deferred Compensation Agreement, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.48.
*10.45[1]	Form of Termination of IDACORP, Inc. Director Deferred Compensation Agreement, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.49.
*10.46[1]	Form of Idaho Power Company Director Deferred Compensation Agreement, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.50.
*10.47[1]	Form of Letter Agreement to Amend Outstanding Idaho Power Company Director Deferred Compensation Agreement (November 16, 2008). File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.51.
*10.48[1]	Form of Amendment to Idaho Power Company Director Deferred Compensation Agreement, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.52.
*10.49[1]	Form of Termination of Idaho Power Company Director Deferred Compensation Agreement, as amended November 20, 2008. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2008, filed on 2/26/09, as Exhibit 10.53.
*10.50[1]	Idaho Power Company Employee Savings Plan, as amended and restated as of January 1, 2010 (revised). File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2009, filed on 2/23/10, as Exhibit 10.63.
*10.51[1]	Amendment to the Idaho Power Company Employee Savings Plan, dated August 31, 2011. File number 1-14465, 1-3198, Form 10-Q for the quarter ended September 30, 2011, filed on November 3, 2011, as Exhibit 10.72.
*10.52	Second Amended and Restated Credit Agreement, dated October 26, 2011, among IDACORP, Inc., various lenders, Wells Fargo Bank, National Association, as administrative agent, swingline lender, and LC issuer, JPMorgan Chase Bank, N.A., as syndication agent and LC issuer, KeyBank National Association and Union Bank, N.A., as documentation agents, and Wells Fargo Securities, LLC, J.P. Morgan Securities Inc., Keybanc Capital Markets, and Union Bank, N.A. as joint lead arrangers and joint book runners. File number 1-14465, Form 8-K, filed on 10/28/11, as Exhibit 10.70.
*10.53	Second Amended and Restated Credit Agreement, dated October 26, 2011, among Idaho Power Company, various lenders, Wells Fargo Bank, National Association, as administrative agent, swingline lender, and LC issuer, JPMorgan Chase Bank, N.A., as syndication agent and LC issuer, KeyBank National Association and Union Bank, N.A., as documentation agents, and Wells Fargo Securities, LLC, J.P. Morgan Securities Inc., Keybanc Capital Markets, and Union Bank, N.A. as joint lead arrangers and joint book runners.. File number 1-3198, Form 8-K, filed on 10/28/11, as Exhibit 10.71.
*10.54	Loan Agreement, dated October 1, 2006, between Sweetwater County, Wyoming and Idaho Power Company. File number 1-3198, Form 8-K, filed on 10/10/06, as Exhibit 10.1.
*10.55	Guaranty Agreement, dated February 10, 1992, between Idaho Power Company and New York Life Insurance Company, as Note Purchaser, relating to $11,700,000 Guaranteed Notes due 2017 of Milner Dam Inc. File number 33-65720, Form S-3, filed on 7/7/93, as Exhibit 10(m)(i).

Exhibit No.	Description
*10.56	Contract for Engineering, Procurement and Construction Services, dated May 7, 2009, between Idaho Power Company and Boise Power Partners Joint Venture, a joint venture consisting of Kiewit Power Engineers Co. and TIC-The Industrial Company, for Langley Gulch Power Plant (Portions of this exhibit have been redacted and filed separately with the Securities and Exchange Commission ("Commission") in accordance with (i) a request for, and related Order by the Commission dated October 21, 2009, File No. 001-14465 - CF#23941, granting, confidential treatment for portions of the EPC Agreement and Exhibit A thereto pursuant to Rule 24b-2 under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), and (ii) a request for, and related Order by the Commission dated December 21, 2010, File No. 001-14465 - CF#25857, granting, confidential treatment pursuant to Rule 24b-2 under the Exchange Act for portions of Exhibits B, C, D, F, I, L, M, and P to the EPC Agreement). File number 1-14465, 1-3198, Form 10-Q/A for the quarter ended September 30, 2010, filed on 12/13/10 as Exhibit 10.44.
*10.57	Amended and Restated Electric Service Agreement between Idaho Power Company and Hoku Materials, Inc., dated June 19, 2009. File number 1-14465, 1-3198, Form 10-Q for the quarter ended June 30, 2009, filed on 8/6/09, as Exhibit 10.45.
*10.58	Joint Purchase and Sale Agreement, dated April 30, 2010, by and between Idaho Power Company and PacifiCorp. File number 1-14465, 1-3198, Form 10-Q for the quarter ended June 30, 2010, filed on 8/5/10, as Exhibit 10.69.
*10.59	Hemingway Joint Ownership and Operating Agreement, dated May 3, 2010, by and between Idaho Power Company and PacifiCorp. File number 1-14465, 1-3198, Form 10-Q for the quarter ended June 30, 2010, filed on 8/5/10, as Exhibit 10.70.
*10.60	Populus Joint Ownership and Operating Agreement, dated May 3, 2010, by and between Idaho Power Company and PacifiCorp. File number 1-14465, 1-3198, Form 10-Q for the quarter ended June 30, 2010, filed on 8/5/10, as Exhibit 10.71.
12.1	IDACORP, Inc. Statement Re: Computation of Ratio of Earnings to Fixed Charges and Supplemental Ratio of Earnings to Fixed Charges.
12.2	Idaho Power Company Statement Re: Computation of Ratio of Earnings to Fixed Charges and Supplemental Ratio of Earnings to Fixed Charges.
*21.1	Subsidiaries of IDACORP, Inc. File number 1-14465, 1-3198, Form 10-K for the year ended December 31, 2007, filed on 2/28/08, as Exhibit 21.
23.1	Consent of Independent Registered Public Accounting Firm.
31.1	IDACORP, Inc. Rule 13a-14(a) CEO certification.
31.2	IDACORP, Inc. Rule 13a-14(a) CFO certification.
31.3	Idaho Power Company Rule 13a-14(a) CEO certification.
31.4	Idaho Power Company Rule 13a-14(a) CFO certification.
32.1	IDACORP, Inc. Section 1350 CEO certification.
32.2	IDACORP, Inc. Section 1350 CFO certification.
32.3	Idaho Power Company Section 1350 CEO certification.
32.4	Idaho Power Company Section 1350 CFO certification.
95.1	Mine safety disclosures.
101.INS[2]	XBRL Instance Document.
101.SCH[2]	XBRL Taxonomy Extension Schema Document.
101.CAL[2]	XBRL Taxonomy Extension Calculation Linkbase Document.
101.LAB[2]	XBRL Taxonomy Extension Label Linkbase Document.

Exhibit No.	Description
101.PRE[2]	XBRL Taxonomy Extension Presentation Linkbase Document.
101.DEF[2]	XBRL Taxonomy Extension Definition Linkbase Document.

1 Management contract or compensatory plan or arrangement

2 Includes data files for the following materials from the annual report on Form 10-K of IDACORP, Inc. for the year ended December 31, 2011, formatted in Extensible Business Reporting Language (XBRL): (i) the Consolidated Statements of Income; (ii) the Consolidated Balance Sheets; (iii) the Consolidated Statements of Cash Flows; (iv) the Consolidated Statements of Comprehensive Income; (v) the Consolidated Statements of Equity; and (vi) the Notes to Consolidated Financial Statements. Also includes data files for the following materials from the annual report on Form 10-K of Idaho Power Company for the year ended December 31, 2011 formatted in XBRL: (i) Consolidated Statements of Income; (ii) Consolidated Balance Sheets; (iii) Consolidated Statements of Capitalization; (iv) Consolidated Statements of Cash Flows; (v) Consolidated Statements of Comprehensive Income; and (vi) the Notes to Consolidated Financial Statements tagged as blocks of text. Detailed tags for information in the Notes to Condensed Consolidated Financial Statements are being furnished only by IDACORP, Inc. and not by its subsidiary, Idaho Power Company. Pursuant to Rule 406T of SEC Regulation S-T, these interactive data files are deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, are deemed not filed for purposes of Section 18 of the Securities Exchange Act of 1934, and otherwise are not subject to liability under those sections.

IDACORP, INC.
SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF REGISTRANT

CONDENSED STATEMENTS OF INCOME

	Year Ended December 31,		
	2011	**2010**	**2009**
	(thousands of dollars)		
Income:			
Equity in income of subsidiaries	$ 166,716	$ 143,414	$ 125,567
Investment income (losses)	161	602	404
Total income	166,877	144,016	125,971
Expenses:			
Operating expenses	1,011	1,130	2,629
Interest expense	534	1,023	919
Other expenses	—	57	66
Total expenses	1,545	2,210	3,614
Income from Before Income Taxes	165,332	141,806	122,357
Income Tax Benefit	(1,361)	(992)	(1,993)
Net Income Attributable to IDACORP, Inc.	$ 166,693	$ 142,798	$ 124,350

The accompanying note is an integral part of these statements.

IDACORP, INC.
CONDENSED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2011	**2010**	**2009**
	(thousands of dollars)		
Operating Activities:			
Net cash provided by operating activities	$ 74,618	$ 29,303	$ 65,406
Investing Activities:			
Contributions to subsidiaries	(16,000)	(50,000)	(20,000)
Sale of investments	621	553	48
Net cash used in investing activities	(15,379)	(49,447)	(19,952)
Financing Activities:			
Issuance of common stock	17,501	48,644	24,328
Dividends on common stock	(59,668)	(57,872)	(56,819)
Increase (decrease) in short-term borrowings	(12,700)	13,150	15,350
Change in intercompany notes payable	(805)	(8,266)	(3,425)
Other	(1,612)	(1,051)	(1,659)
Net cash used in financing activities	(57,284)	(5,395)	(22,225)
Net (decrease) increase in cash and cash equivalents	1,955	(25,539)	23,229
Cash and cash equivalents at beginning of year	1,231	26,770	3,541
Cash and cash equivalents at end of year	$ 3,186	$ 1,231	$ 26,770

The accompanying note is an integral part of these statements.

IDACORP, INC.
CONDENSED BALANCE SHEETS

	December 31,	
	2011	2010
Assets	(thousands of dollars)	
Current Assets:		
Cash and cash equivalents	$ 3,186	$ 1,231
Receivables	2,751	2,284
Deferred income taxes	2,048	3,370
Other	118	751
Total current assets	8,103	7,636
Investment in subsidiaries	1,641,479	1,523,520
Other Assets:		
Deferred income taxes	82,250	92,934
Other	473	149
Total other assets	82,723	93,083
Total assets	$ 1,732,305	$ 1,624,239
Liabilities and Shareholders' Equity		
Current Liabilities:		
Notes payable	$ 54,200	$ 66,900
Accounts payable	6,183	5,945
Taxes accrued	4,376	7,852
Other	669	714
Total current liabilities	65,428	81,411
Other Liabilities:		
Intercompany notes payable	7,149	7,954
Other	2,074	2,761
Total other liabilities	9,223	10,715
IDACORP, Inc. Shareholders' Equity	1,657,654	1,532,113
Total Liabilities and Shareholders' Equity	$ 1,732,305	$ 1,624,239

The accompanying note is an integral part of these statements.

NOTE TO CONDENSED FINANCIAL STATEMENTS

1. BASIS OF PRESENTATION

Pursuant to rules and regulations of the Securities and Exchange Commission, the unconsolidated condensed financial statements of IDACORP, Inc. do not reflect all of the information and notes normally included with financial statements prepared in accordance with accounting principles generally accepted in the United States of America. Therefore, these financial statements should be read in conjunction with the consolidated financial statements and related notes included in the 2011 Form 10-K, Part II, Item 8.

Accounting for Subsidiaries: IDACORP has accounted for the earnings of its subsidiaries under the equity method in the unconsolidated condensed financial statements. Included in net cash provided by operating activities in the condensed statements of cash flows are dividends of $63 million, $61 million, and $60 million that IDACORP subsidiaries paid to IDACORP in 2011, 2010, and 2009, respectively.

IDACORP, INC.
SCHEDULE II - CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
Years Ended December 31, 2011, 2010, and 2009

Column A	Column B	Column C		Column D	Column E
		Additions			
Classification	Balance at Beginning of Year	Charged to Income	Charged (Credited) to Other Accounts	Deductions[1]	Balance at End of Year
		(thousands of dollars)			
2011:					
Reserves deducted from applicable assets					
Reserve for uncollectible accounts	$ 1,640	$ 4,277	$ 161	$ 4,643	$ 1,435
Reserve for uncollectible notes	3,190	(447)	—	—	2,743
Other Reserves:					
Injuries and damages	1,882	783	—	740	1,925
Miscellaneous operating reserves	2,611	—	—	2,611	—
2010:					
Reserves deducted from applicable assets					
Reserve for uncollectible accounts	$ 1,990	$ 5,764	$ (324)	$ 5,790	$ 1,640
Reserve for uncollectible notes	3,045	444	—	299	3,190
Other Reserves:					
Injuries and damages	3,413	400	—	1,931	1,882
Miscellaneous operating reserves	2,926	10	—	325	2,611
2009:					
Reserves deducted from applicable assets					
Reserve for uncollectible accounts	$ 1,724	$ 5,314	$ 122	$ 5,170	$ 1,990
Reserve for uncollectible notes	1,879	566	600	—	3,045
Other Reserves:					
Rate refunds	13,345	—	—	13,345	—
Injuries and damages	1,965	4,867	—	3,419	3,413
Miscellaneous operating reserves	—	2,926	—	—	2,926

[1] Represents deductions from the reserves for purposes for which the reserves were created. In the case of uncollectible accounts, and notes reserves, includes reversals of amounts previously written off.

IDAHO POWER COMPANY
SCHEDULE II - CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
Years Ended December 31, 2011, 2010, and 2009

Column A	Column B	Column C		Column D	Column E
		Additions			
Classification	Balance at Beginning of Year	Charged to Income	Charged (Credited) to Other Accounts	Deductions[1]	Balance at End of Year
		(thousands of dollars)			
2011:					
Reserves deducted from applicable assets					
Reserve for uncollectible accounts	$ 1,640	$ 4,277	$ 161	$ 4,643	$ 1,435
Other Reserves:					
Injuries and damages	1,882	783	—	740	1,925
Miscellaneous operating reserves	2,611	—	—	2,611	—
2010:					
Reserves deducted from applicable assets					
Reserve for uncollectible accounts	$ 1,990	$ 5,764	$ (324)	$ 5,790	$ 1,640
Other Reserves:					
Injuries and damages	3,413	400	—	1,931	1,882
Miscellaneous operating reserves	2,926	10	—	325	2611
2009:					
Reserves deducted from applicable assets					
Reserve for uncollectible accounts	$ 1,724	$ 5,314	$ 122	$ 5,170	$ 1,990
Other Reserves:					
Rate refunds	13,345	—	—	13,345	—
Injuries and damages	1,965	4,867	—	3,419	3,413
Miscellaneous operating reserves	—	2,926	—	—	2,926

[1] Represents deductions from the reserves for purposes for which the reserves were created. In the case of uncollectible accounts, includes reversals of amounts previously written off.

SIGNATURES

Pursuant to the requirements of Section 13 and 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

February 22, 2012		IDACORP, INC.
Date		
	By:	*/s/ J. LaMont Keen*
		J. LaMont Keen
		President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Gary G. Michael Gary G. Michael	Chairman of the Board	February 22, 2012
/s/ J. LaMont Keen J. LaMont Keen President and Chief Executive Officer and Director	(Principal Executive Officer)	February 22, 2012
/s/ Darrel T. Anderson Darrel T. Anderson Executive Vice President-Administrative Services and Chief Financial Officer	(Principal Financial Officer)	February 22, 2012
/s/ Kenneth W. Petersen Kenneth W. Petersen Corporate Controller and Chief Accounting Officer	(Principal Accounting Officer)	February 22, 2012
/s/ C. Stephen Allred C. Stephen Allred	Director	February 22, 2012
/s/ Richard J. Dahl Richard J. Dahl	Director	February 22, 2012
/s/ Judith A. Johansen Judith A. Johansen	Director	February 22, 2012
/s/ Christine King Christine King	Director	February 22, 2012
/s/ Jan B. Packwood Jan B. Packwood	Director	February 22, 2012
/s/ Richard G. Reiten Richard G. Reiten	Director	February 22, 2012
/s/ Joan H. Smith Joan H. Smith	Director	February 22, 2012
/s/ Robert A. Tinstman Robert A. Tinstman	Director	February 22, 2012
/s/ Thomas J. Wilford Thomas J. Wilford	Director	February 22, 2012

SIGNATURES

Pursuant to the requirements of Section 13 and 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

February 22, 2012		Idaho Power Company
Date		
	By:	*/s/ J. LaMont Keen*
		J. LaMont Keen
		Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Gary G. Michael Gary G. Michael	Chairman of the Board	February 22, 2012
/s/ J. LaMont Keen J. LaMont Keen Chief Executive Officer and Director	(Principal Executive Officer)	February 22, 2012
/s/ Darrel T. Anderson Darrel T. Anderson President and Chief Financial Officer	(Principal Financial Officer)	February 22, 2012
/s/ Kenneth W. Petersen Kenneth W. Petersen Corporate Controller and Chief Accounting Officer		February 22, 2012
/s/ C. Stephen Allred C. Stephen Allred	Director	February 22, 2012
/s/ Richard J. Dahl Richard J. Dahl	Director	February 22, 2012
/s/ Judith A. Johansen Judith A. Johansen	Director	February 22, 2012
/s/ Christine King Christine King	Director	February 22, 2012
/s/ Jan B. Packwood Jan B. Packwood	Director	February 22, 2012
/s/ Richard G. Reiten Richard G. Reiten	Director	February 22, 2012
/s/ Joan H. Smith Joan H. Smith	Director	February 22, 2012
/s/ Robert A. Tinstman Robert A. Tinstman	Director	February 22, 2012
/s/ Thomas J. Wilford Thomas J. Wilford	Director	February 22, 2012

IDACORP, Inc. is committed to doing its part to be responsible stewards of our environment. This annual report was printed on a combination of environmentally friendly papers using soy-based inks.

Cover and narrative pages

These pages were printed on Opus 30 Sheets manufactured by Sappi Fine Paper North America with:

- FSC® Chain of Custody Certification
- A minimum of 30% Post Consumer Waste (PCW) fiber
- 100% Green-e certified renewable energy

Financial pages

These pages were printed on Accent Sheets manufactured by International Paper with:

- FSC® Chain of Custody Certification

MIX
Paper from responsible sources
FSC® C016131

By printing on post-consumer fiber in place of virgin timber, we achieved the following savings:

10	trees preserved for the future
29	pounds of water-borne waste not created
4,228	gallons of wastewater flow saved
468	pounds of solid waste not generated
921	pounds net greenhouse gases prevented

As compared to the industry average, the amount of greenhouse gas emissions avoided are equivalent to one of the following:

126	gallons of gasoline consumed
47	propane cylinders
758	pounds of waste recycled instead of sent to landfills

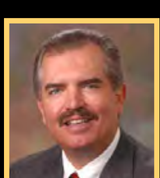
IDACORP and Idaho Power Board of Directors

above photo by Idaho Power customer Lisa Kidd, www.facebook.com/LisaKiddPhotography

C. Stephen Allred
(2009) Boise, Idaho
Formerly Assistant Secretary for U.S. Land and Minerals Management; formerly Director of the Idaho Department of Environmental Quality; formerly Director of Idaho Department of Water Resources; and formerly President of Morrison-Knudson's Environmental and Government Services Group

Richard J. Dahl
(2008) Kapolei, Hawaii
Chairman of the Board, President and Chief Executive Officer of James Campbell Company, LLC; Chairman of the Board, International Rectifiers Corp; Director, Dine Equity, Inc.; and formerly President and Chief Operating Officer of Dole Food Company

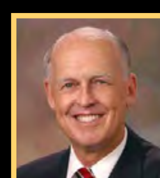
Judith A. Johansen
(2007) Lake Oswego, Oregon
President of Marylhurst University; Director, Cascade Bancorp, Schnitzer Steel and Roseburg Forest Products; formerly President and Chief Executive Officer of PacifiCorp; and formerly Chief Executive Officer and Administrator of Bonneville Power Administration



J. LaMont Keen
(2004) Boise, Idaho
President and Chief Executive Officer, IDACORP, Inc. and Chief Executive Officer, Idaho Power; Board of Directors, Cascade Bancorp

Christine King
(2006) Hauppague, New York
President and Chief Executive Officer of Standard Microsystems Corporation; Director, Atheros Communications, Inc., Open-Silicon, Inc., and Standard Microsystem Corporation; and formerly President and Chief Executive Officer of AMI Semiconductor; formerly Director of Atheros Communications, Inc.

Gary G. Michael*
(2001) Boise, Idaho
Chairman of the Board, IDACORP, Inc. and Idaho Power; Director, The Clorox Co., Questar Corporation, Questar Gas, Questar Pipeline and Graham Packaging Co.; and formerly Chief Executive Officer of Albertsons, Inc.



Jan B. Packwood
(1997) Boise, Idaho
Formerly President and Chief Executive Officer of IDACORP, Inc.; Director of Westmoreland Coal Company

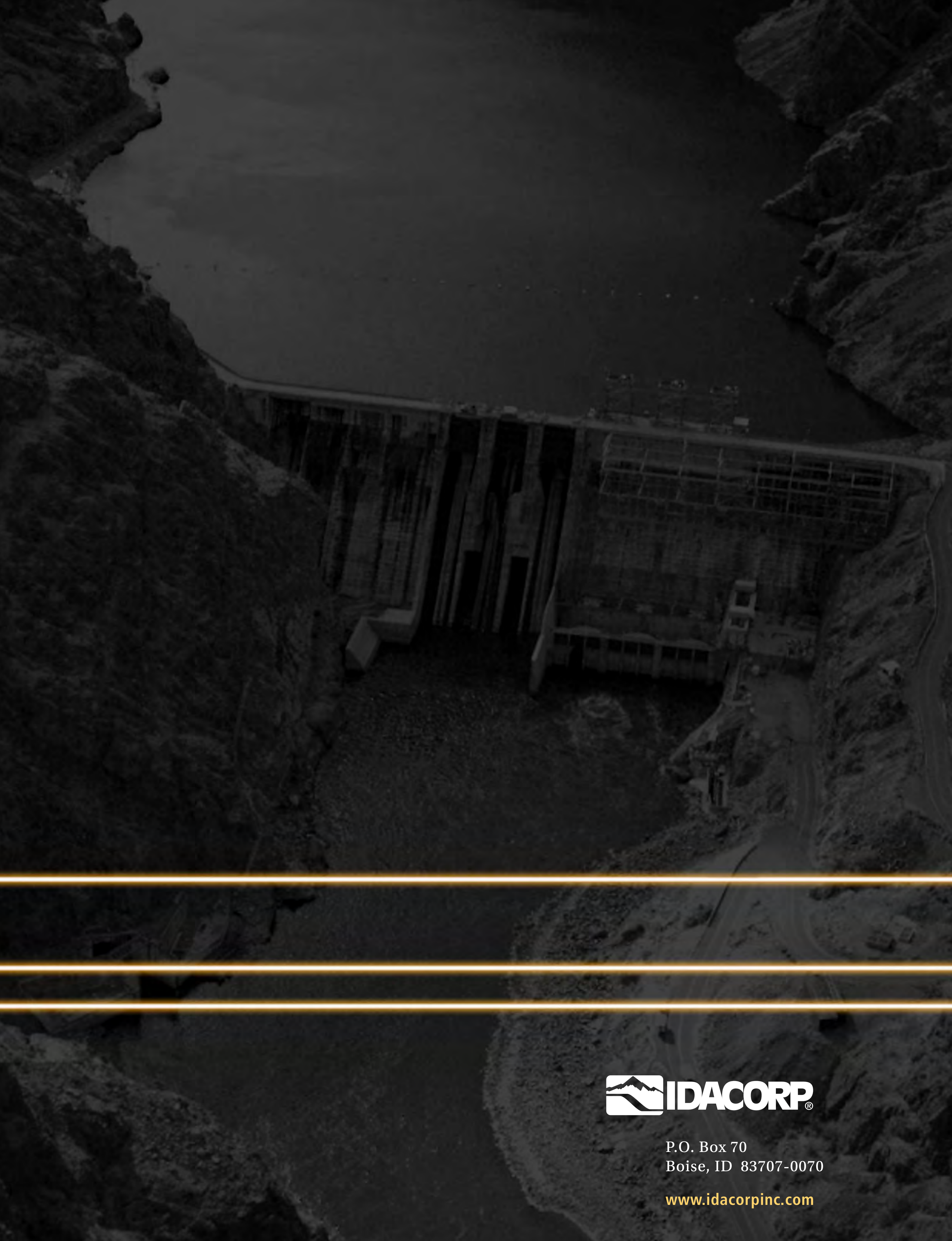
Richard G. Reiten
(2004) Portland, Oregon
Director, U.S. Bancorp; National Fuel Gas Co.; formerly President and Chief Executive Officer of Northwest Natural Gas Company; and formerly President and Chief Operating Officer of Portland General Electric

Joan H. Smith
(2004) Portland, Oregon
Self-employed consultant, consulting on regulatory strategy and telecommunications; and formerly Oregon Public Utility Commissioner

Robert A. Tinstman
(1999) Boise, Idaho
Director, Primoris Services Corp.; Home Federal Bancorp, Inc. and CNA Surety Corp.; and formerly President and Chief Executive Officer of Morrison-Knudsen Corporation

Thomas J. Wilford
(2004) Boise, Idaho
President of Alscott, Inc.; Chief Executive Officer of J.A. and Kathryn Albertson Foundation, Inc.; former Director, K12, Inc.

( ) year elected to the board
* Chairman of the Board



IDACORP®

P.O. Box 70
Boise, ID 83707-0070

www.idacorpinc.com