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

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2016)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2016)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2016)

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** 2014/Q4

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	04/15/2015	End of 2014/Q4

LIST OF SCHEDULES (Electric Utility)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	
4	Officers	104	
5	Directors	105	
6	Information on Formula Rates	106(a)(b)	
7	Important Changes During the Year	108-109	
8	Comparative Balance Sheet	110-113	
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10	Statement of Retained Earnings for the Year	118-119	
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13	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
14	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
15	Nuclear Fuel Materials	202-203	N/A
16	Electric Plant in Service	204-207	
17	Electric Plant Leased to Others	213	
18	Electric Plant Held for Future Use	214	
19	Construction Work in Progress-Electric	216	
20	Accumulated Provision for Depreciation of Electric Utility Plant	219	
21	Investment of Subsidiary Companies	224-225	
22	Materials and Supplies	227	
23	Allowances	228(ab)-229(ab)	N/A
24	Extraordinary Property Losses	230	N/A
25	Unrecovered Plant and Regulatory Study Costs	230	N/A
26	Transmission Service and Generation Interconnection Study Costs	231	
27	Other Regulatory Assets	232	
28	Miscellaneous Deferred Debits	233	
29	Accumulated Deferred Income Taxes	234	
30	Capital Stock	250-251	
31	Other Paid-in Capital	253	
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33	Long-Term Debt	256-257	
34	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
35	Taxes Accrued, Prepaid and Charged During the Year	262-263	
36	Accumulated Deferred Investment Tax Credits	266-267	

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".

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 Line Statistics Pages	422-423	
68	Transmission Lines Added During the Year	424-425	
69	Substations	426-427	
70	Transactions with Associated (Affiliated) Companies	429	
71	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	04/15/2015	End of 2014/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 Vice President,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	04/15/2015	End of 2014/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

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

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

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Direct Control			
2	Idaho Energy Resources Company	Coal mining and mineral	100%	
3		development		
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

OFFICERS

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

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1			
2	President & Chief Executive Officer	Darrel T. Anderson	575,000
3			
4	Executive Vice President & Chief Operating Officer	Dan Minor	430,000
5			
6	Senior Vice President & General Counsel	Rex Blackburn	335,000
7			
8	Senior Vice President, Power Supply	Lisa Grow	300,000
9			
10	Senior Vice President, CFO & Treasurer	Steven Keen	315,000
11			
12	Vice President, Human Resources & Corporate Services	Luci McDonald	265,000
13			
14	Vice President, Customer Operations	Warren Kline	260,000
15			
16	Vice President, Public Affairs	Jeffrey Malmen	245,000
17			
18	Vice President, & Chief Risk Officer	Lori Smith	233,000
19			
20	Vice President Delivery, Engineering & Construction	Vern Porter	235,000
21			
22	Vice President,Controller & Chief Accounting Officer	Ken Petersen	215,000
23			
24	Vice President & Chief Information Officer	Lonnie Krawl	208,000
25			
26	Vice President, Regulatory Affairs	Gregory Said	210,000
27			
28	Corporate Secretary	Patrick Harrington	182,000
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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	1809 Headlee Lane, Lake Oswego, Oregon 97034
3		
4	Christine King***	8527 East old Field Rd
5		Scottsdale, Azizona 85266
6		
7	Stephen Allred (1)	4642 W Dawson Dr., Meridian, Idaho 83646
8		
9	Jan B. Packwood	900 W. Bogus View Drive, Eagle, Idaho 83616
10		
11	Darrel T. Anderson President & Chief Executive Office	Idaho Power Company, 1221 W. Idaho Street,
12		P.O. Box 70, Boise, Idaho 83707-0070
13		
14	J. LaMont Keen, ** ***	481 North Strata Via Way, Boise Idaho 83712
15		
16		
17	Joan Smith	2309 S.W. First Avenue, No. 1141, Portland, Oregon 97201
18		
19	Robert A. Tinstman ***	4433 W. Quail Point Court, Boise, Idaho 83703
20		
21	Thomas Wilford	1504 Warm Springs Avenue
22		Boise, Idaho 83712
23		
24	Richard Dahl ***	60 Laiki Pl.
25		Kailua, Hawaill 96734
26		
27	Dennis L. Johnson	United Heritage Life Insurance
28		707 E. United Heritage Ct., Ste 130, Meridian, Idaho 83642
29		
30	Ronald W. Jibson	Questar Corporation
31		333 South State Street, Salt Lake City, Utah 84145-0433
32		
33	Thomas Carlile (2)	2719 North Woodview place, Boise Idaho 83702
34		
35		
36		
37	(1) Retired on May 15, 2014	
38	(2) Appointed to Board March 19, 2014	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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	
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Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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	201408285251	08/28/2014	ER09-1641-000	Idaho Power Company	FERC Electric Tariff
2				2014 Annual	
3				informational filing	
4				under ER-09-1641-000	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

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

Line No.	Page No(s).	Schedule	Column	Line No
1	None			
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
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IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 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. Line #134 Line was rerouted into Bowmont substation. A portion was removed from underbuild on line 248 and given its own alignment farther South.
Line #248 Removed de-energized line around Chestnut substation.
Line #464 Added .36 miles to reroute around the new hwy 16/44 intersection.
Line #479 A new 138kv line was placed in service between Bowmont and Happy Valley substations. 8.64 miles

There continues to be realignment using LiDar data and Aerial photos. This realignment will result in small additions or deletions to line lenghts. There were several other lines where data errors or omissions have also been corrected.

6. As of December 31,2014 Idaho Power had not sold any first mortgage bonds, including Series J notes, or debt securities under the selling agency agreement.

7. None

8. Effective 1/04/2014 a 3.0 general wage adjustment was implemented.

9. See pages 123.19 to 123.20

10. None

11. None

12. None

13. Idaho Power has added Thomas Carlile as a director effective 3/19/2014. Stephen Allred retired effective 5/15/2014.

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 advance from Idaho Power to IDACORP through a cash management program.

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COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	5,255,302,762	5,087,492,230
3	Construction Work in Progress (107)	200-201	401,929,509	327,000,038
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		5,657,232,271	5,414,492,268
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	2,021,073,827	1,940,654,182
6	Net Utility Plant (Enter Total of line 4 less 5)		3,636,158,444	3,473,838,086
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)		3,636,158,444	3,473,838,086
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		1,555,480	1,274,121
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	83,477,460	91,384,573
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)		647	824
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		45,082,335	42,271,755
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		63,323	288,132
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		130,179,245	135,219,405
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		46,581,578	66,420,846
36	Special Deposits (132-134)		1,079,260	3,106,514
37	Working Fund (135)		13,600	14,100
38	Temporary Cash Investments (136)		100,000	100,000
39	Notes Receivable (141)		0	50,208
40	Customer Accounts Receivable (142)		85,040,915	100,221,798
41	Other Accounts Receivable (143)		14,677,441	11,336,452
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		4,650,829	2,501,686
43	Notes Receivable from Associated Companies (145)		2,053,197	0
44	Accounts Receivable from Assoc. Companies (146)		0	0
45	Fuel Stock (151)	227	55,170,482	41,546,323
46	Fuel Stock Expenses Undistributed (152)	227	599	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	50,305,479	49,267,705
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

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	5,098,760	4,375,589
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)		18,355,589	15,204,045
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		56,269,642	63,506,686
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		634,183	1,672,362
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		63,323	288,132
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)		330,666,573	354,032,810
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		15,815,910	17,183,115
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	1,237,823,724	1,036,375,119
73	Prelim. Survey and Investigation Charges (Electric) (183)		873,939	883,871
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)		1,053,324	2,147,654
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	45,564,713	45,208,766
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)		12,799,888	13,860,473
82	Accumulated Deferred Income Taxes (190)	234	289,103,584	246,774,821
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,603,035,082	1,362,433,819
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		5,700,039,344	5,325,524,120

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	04/15/2015	end of 2014/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	97,877,030	97,877,030
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		712,257,435	712,257,435
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	952,335,875	843,625,028
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	81,014,366	88,921,479
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)	-24,157,999	-16,553,375
16	Total Proprietary Capital (lines 2 through 15)		1,817,229,782	1,724,030,672
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,595,460,000	1,595,460,000
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	23,075,909	24,139,545
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		3,034,022	3,277,591
24	Total Long-Term Debt (lines 18 through 23)		1,615,501,887	1,616,321,954
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)		1,994,972	1,670,695
29	Accumulated Provision for Pensions and Benefits (228.3)		403,474,921	245,780,272
30	Accumulated Miscellaneous Operating Provisions (228.4)		3,865,254	2,771,356
31	Accumulated Provision for Rate Refunds (229)		72,974,757	59,388,816
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		21,930,049	25,765,364
35	Total Other Noncurrent Liabilities (lines 26 through 34)		504,239,953	335,376,503
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		113,979,552	105,671,106
39	Notes Payable to Associated Companies (233)		0	13,264,181
40	Accounts Payable to Associated Companies (234)		2,027,220	1,158,063
41	Customer Deposits (235)		1,568,822	1,428,221
42	Taxes Accrued (236)	262-263	-10,635,253	15,104,410
43	Interest Accrued (237)		22,670,165	22,834,804
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	end of 2014/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		2,599,099	1,444,649
48	Miscellaneous Current and Accrued Liabilities (242)		40,889,480	35,788,243
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		3,960,704	571,747
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		0	0
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	0
54	Total Current and Accrued Liabilities (lines 37 through 53)		177,059,789	197,265,424
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		3,303,553	9,465,217
57	Accumulated Deferred Investment Tax Credits (255)	266-267	79,162,831	79,121,290
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	11,635,642	12,386,721
60	Other Regulatory Liabilities (254)	278	64,843,269	70,377,000
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)		1,248,630,361	1,143,090,466
64	Accum. Deferred Income Taxes-Other (283)		178,432,277	138,088,873
65	Total Deferred Credits (lines 56 through 64)		1,586,007,933	1,452,529,567
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		5,700,039,344	5,325,524,120

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	04/15/2015	End of 2014/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	1,277,640,977	1,242,150,868		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	780,281,536	710,931,086		
5	Maintenance Expenses (402)	320-323	68,283,304	67,728,722		
6	Depreciation Expense (403)	336-337	125,245,540	121,486,191		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	495,029	587,012		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	7,172,382	7,611,634		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		73,650	56,176		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	31,748,230	30,560,823		
15	Income Taxes - Federal (409.1)	262-263	-7,413,733	9,918,700		
16	- Other (409.1)	262-263	6,908,583	5,499,764		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	152,963,217	138,292,290		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	134,837,097	82,501,409		
19	Investment Tax Credit Adj. - Net (411.4)	266	41,541	-775,313		
20	(Less) Gains from Disp. of Utility Plant (411.6)			6,043		
21	Losses from Disp. of Utility Plant (411.7)			6,766		
22	(Less) Gains from Disposition of Allowances (411.8)		186,382	41,307		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		309,716	322,348		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,031,085,516	1,009,677,440		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		246,555,461	232,473,428		

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	04/15/2015	End of 2014/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

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

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	Line No.
						1
1,277,640,977	1,242,150,868					2
						3
780,281,536	710,931,086					4
68,283,304	67,728,722					5
125,245,540	121,486,191					6
495,029	587,012					7
7,172,382	7,611,634					8
						9
						10
						11
73,650	56,176					12
						13
31,748,230	30,560,823					14
-7,413,733	9,918,700					15
6,908,583	5,499,764					16
152,963,217	138,292,290					17
134,837,097	82,501,409					18
41,541	-775,313					19
	6,043					20
	6,766					21
186,382	41,307					22
						23
309,716	322,348					24
1,031,085,516	1,009,677,440					25
246,555,461	232,473,428					26

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)		246,555,461	232,473,428		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		1,009,910	946,897		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		1,136,669	1,079,771		
33	Revenues From Nonutility Operations (417)		37,547	41,993		
34	(Less) Expenses of Nonutility Operations (417.1)		22,828	60,482		
35	Nonoperating Rental Income (418)		-527	-2,844		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	7,092,887	6,704,329		
37	Interest and Dividend Income (419)		2,704,620	2,426,000		
38	Allowance for Other Funds Used During Construction (419.1)		17,930,898	14,857,580		
39	Miscellaneous Nonoperating Income (421)		2,453,947	14,488,869		
40	Gain on Disposition of Property (421.1)		-4,240	-2,442		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		30,065,545	38,320,129		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		2,156	1,917		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		747,094	744,976		
46	Life Insurance (426.2)		-1,164,064	-18,319		
47	Penalties (426.3)		27,106	428,042		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,561,921	1,282,131		
49	Other Deductions (426.5)		8,332,431	8,655,953		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		9,506,644	11,094,700		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	24,797	22,991		
53	Income Taxes-Federal (409.2)	262-263	-914,126	1,540,870		
54	Income Taxes-Other (409.2)	262-263	-41,215	417,095		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	1,085,673	2,496,132		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	2,008,392	2,173,220		
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)		-1,853,263	2,303,868		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		22,412,164	24,921,561		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		80,561,920	81,492,149		
63	Amort. of Debt Disc. and Expense (428)		1,610,773	1,609,364		
64	Amortization of Loss on Reaquired Debt (428.1)		1,060,585	1,060,585		
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)		10,524	7,955		
68	Other Interest Expense (431)		4,800,939	4,146,983		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		8,464,109	7,663,190		
70	Net Interest Charges (Total of lines 62 thru 69)		79,580,632	80,653,846		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		189,386,993	176,741,143		
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)		189,386,993	176,741,143		

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	04/15/2015	End of 2014/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		836,965,502	749,111,203
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)		182,294,106	170,036,814
17	Appropriations of Retained Earnings (Acct. 436)			
18		215.1	-6,613,580	(3,256,123)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-6,613,580	(3,256,123)
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			-88,583,259	(78,926,392)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-88,583,259	(78,926,392)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings	216	15,000,000	
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		939,062,769	836,965,502
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

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)		13,273,106	6,659,526
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		13,273,106	6,659,526
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		952,335,875	843,625,028
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		88,921,479	82,217,150
50	Equity in Earnings for Year (Credit) (Account 418.1)		7,092,887	6,704,329
51	(Less) Dividends Received (Debit)		15,000,000	
52				
53	Balance-End of Year (Total lines 49 thru 52)		81,014,366	88,921,479

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	04/15/2015	End of 2014/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)	189,386,993	176,741,143
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	125,245,540	121,486,191
5	Amortization of Note 1	11,250,901	11,648,544
6			
7			
8	Deferred Income Taxes (Net)	17,218,276	55,836,153
9	Investment Tax Credit Adjustment (Net)	26,665	-497,674
10	Net (Increase) Decrease in Receivables	22,570,540	-30,953,272
11	Net (Increase) Decrease in Inventory	-15,385,702	-1,213,152
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-18,687,818	7,503,331
14	Net (Increase) Decrease in Other Regulatory Assets	16,794,041	-40,694,556
15	Net Increase (Decrease) in Other Regulatory Liabilities	15,341,861	15,112,871
16	(Less) Allowance for Other Funds Used During Construction	17,930,898	14,857,580
17	(Less) Undistributed Earnings from Subsidiary Companies	-7,907,113	6,704,329
18	Other (provide details in footnote): Note 2	4,789,855	-17,772,390
19			
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	358,527,367	275,635,280
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-291,841,495	-250,164,015
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	-17,930,898	-14,857,580
31	Other (provide details in footnote): Note 3	3,551,443	498,473
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-270,359,154	-234,807,962
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	-15,317,379	14,272,430
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)	-8,000,000	-32,660,820
45	Proceeds from Sales of Investment Securities (a)		25,660,820

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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	50,208	22,284
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): Note 4	4,906,085	3,450,425
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-288,720,240	-224,062,823
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		150,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):		
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)		150,000,000
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-1,063,636	-71,063,636
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		-2,298,726
77			
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-88,583,259	-78,926,392
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-89,646,895	-2,288,754
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-19,839,768	49,283,703
87			
88	Cash and Cash Equivalents at Beginning of Period	66,534,946	17,251,243
89			
90	Cash and Cash Equivalents at End of period	46,695,178	66,534,946

FOOTNOTE DATA

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

Plant	7,172,382
Unamortized debt expense	2,728,016
Unamortized discount	243,569
Water rights	1,042,009
Other	64,925
	11,250,901

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

Cash paid during the period for:	
Income taxes	22,202,480
Interest (net of amount capitalized)	77,063,389

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

Cash Flow from Operating Activities (Other)	
Pension and postretirement benefit plan expense	44,578,826
Contributions to pension and postretirement benefit plans	(33,672,415)
Unbilled revenues	7,237,044
Prepayments	(4,988,374)
Company owned life insurance	(1,856,230)
Customer deposits	(5,746,063)
Other	(762,933)
	4,789,855

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

Non-cash investing activities:	
Additions to PP&E in accounts payable	28,438,385

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

Other Cash Flows from Plant	
Sale of utility property	620,205
Sale of emission allowances and renewable energy certificates	2,931,238
	3,551,443

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

Other Investing Cash Flows

Disbursements from rabbi trust & EDC plan	**4,905,908**
Miscellaneous other investing activities	**177**

	4,906,085

NOTES TO FINANCIAL STATEMENTS

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

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SEE PAGE 123 FOR REQUIRED INFORMATION.

IDAHO POWER COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Idaho Power Company (Idaho Power) is the principal operating subsidiary of IDACORP Inc. (IDACORP), a holding company formed in 1998. Idaho Power is an electric utility with a service area covering approximately 24,000 square miles in southern Idaho and eastern Oregon. Idaho Power is regulated primarily 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.

Basis of Reporting

The financial statements include the assets, liabilities, revenues and expenses of Idaho Power and have been prepared in accordance with the accounting requirements of the FERC as set forth in the 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, Idaho Power accounts for its investments 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 Idaho Power's proportionate share of the utility plant and related operations resulting from its interest in jointly-owned plants. In addition, under the requirements of the FERC, there are differences from U.S. GAAP in the presentation of (1) current portion of long-term debt, (2) assets and liabilities for cost of removal of assets, (3) regulatory assets and liabilities (4) deferred income taxes, (5) income tax expense , (6) non-utility revenues and (7) accrued taxes.

Management Estimates

Management makes estimates and assumptions when preparing these financial statements. 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

As a regulated utility, many of Idaho Power's fundamental business decisions are subject to the approval of governmental agencies, including the prices that Idaho Power is authorized to charge for its electric service. These approvals are a critical factor in determining Idaho Power's results of operations and financial condition.

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 record such expenses and revenues. 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 that are expected to be refunded. 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, 2014 and 2013. 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 unless they are designated as normal purchases and normal sales. With the exception of forward contracts for the purchase of natural gas for use at Idaho Power's natural gas generation facilities and a nominal number of power transactions, Idaho Power's physical forward contracts are designated as normal purchases and normal sales. 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 Complex (HCC) 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 2.68 percent in 2014 and 2.69 percent in 2013.

During the period of construction, costs expected to be included in the final value of the constructed asset, and depreciated once the asset is complete and placed in service, are classified as construction work in progress on the consolidated balance sheets. If the project becomes probable of being abandoned, such costs are expensed in the period such determination is made. If any costs are expensed, Idaho Power may seek recovery of such costs in customer rates, although there can be no guarantee such recovery would be granted.

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 is recognized in the financial statements. There were no material impairments of these assets in 2014 or 2013.

Allowance for Funds Used During Construction

AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. With one exception, as discussed above for the HCC relicensing project, 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 total interest expense. Idaho Power's weighted-average monthly AFUDC rate was 7.7 percent for 2014 and 2013.

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 (commonly referred to as normalized accounting), 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. In general, deferred income tax expense or benefit for a reporting period is recognized as the change in deferred tax assets and liabilities from the beginning to the end of the period. 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 unless Idaho Power's primary regulator, the Idaho Public Utilities Commission (IPUC), orders direct deferral of the effect of the change in tax rates over a longer period of time.

Consistent with orders and directives of the IPUC, unless contrary to applicable income tax guidance, Idaho Power does not provide deferred income taxes for certain income tax temporary differences and instead recognizes the tax impact currently (commonly referred to as flow-through accounting) for rate making and financial reporting. Therefore, Idaho Power's effective income tax rate is impacted as these differences arise and reverse. 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.

In compliance with the federal income tax requirements for the use of accelerated tax depreciation, Idaho Power provides deferred income taxes related to its plant assets for the difference between income tax depreciation and book depreciation used for financial statement purposes. Deferred income taxes are provided for other temporary differences unless accounted for using flow-through.

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.

Other Accounting Policies

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

Recently Issued Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update (ASU) 2014-09, *Revenue from Contracts with Customers (Topic 606)*. ASU 2014-09 is intended to enable users of financial statements to better understand and consistently analyze an entity's revenue across industries, transactions, and geographies. Under the ASU, recognition of revenue occurs when a customer obtains control of promised goods or services. In addition, the ASU requires disclosure of the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. The amendments in ASU 2014-09 are effective for annual reporting periods beginning after December 15, 2016, including interim periods within that reporting period. Early adoption is not permitted. The guidance permits two implementation approaches, one requiring retrospective application of the new standard with restatement of prior years and one requiring prospective application of the new standard including a cumulative-effect adjustment with disclosure of results under old standards. As such, at Idaho Power's required adoption date of January 1, 2017, amounts in 2015 and 2016 may have to be revised. Idaho Power is currently evaluating the impact of ASU 2014-09 on its financial statements.

Subsequent Events

Management has evaluated the impact of events occurring after December 31, 2014 up to February 19, 2015, the date that Idaho Power Company's U.S. GAAP financial statements were issued and has updated such evaluation for disclosure purposes through April 15, 2015. These financial statements include all necessary adjustments and disclosures resulting from these evaluations.

2. INCOME TAXES

A reconciliation between the statutory federal income tax rate and the effective tax rate is as follows (in thousands of dollars):

	2014	2013
Federal income tax expense at 35% statutory rate	$ 71,810	$ 87,310
Change in taxes resulting from:		
Equity Earnings of subsidiary companies	(2,483)	(2,347)
AFUDC	(9,238)	(7,882)
Capitalized interest	2,278	1,832
Investment tax credits	(3,002)	(3,120)
Removal costs	(3,656)	(3,527)
Capitalized overhead costs	(8,750)	(8,750)
Capitalized repair costs	(26,250)	(19,250)
Tax method change – capitalized repairs	(24,516)	4,583
State income taxes, net of federal benefit	5,334	6,970
Depreciation	16,040	14,820
Other, net	(1,783)	2,076
Total income tax expense	$ 15,784	$ 72,715
Effective tax rate	7.7 %	29.1 %

The items comprising income tax expense are as follows (in thousands of dollars):

	2014	2013
Income taxes current:		
Federal	$ (8,328)	$ 11,460
State	6,867	5,917
Total	(1,461)	17,377
Income taxes deferred:		
Federal	23,624	56,918
State	(6,421)	(804)
Total	17,203	56,114
Investment tax credits:		
Deferred	3,044	2,344
Restored	(3,002)	(3,120)
Total	42	(776)
Total income tax expense	$ 15,784	$ 72,715

The components of the net deferred tax liability are as follows (in thousands of dollars):

	2014	2013
Deferred tax assets:		
Regulatory liabilities	$ 55,490	$ 55,017
Deferred compensation	25,240	23,647
Deferred revenue	28,529	23,062
Tax credits	26,768	23,642
Net operating losses	—	29,628
Retirement benefits	132,571	69,033
Other	14,553	10,359
Total	283,151	234,388
Deferred tax liabilities:		
Property, plant and equipment	451,118	436,837
Regulatory assets	802,188	710,482
Power cost adjustments	23,192	35,763
Retirement benefits	122,360	65,810
Other	22,252	19,901
Total	1,421,110	1,268,793
Net deferred tax liabilities	$ 1,137,959	$ 1,034,405

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. See Note 1 for further discussion of accounting policies related to income taxes.

Uncertain Tax Positions

Idaho Power believes that it has no material income tax uncertainties for 2014 and prior tax years. The company recognizes interest accrued related to unrecognized tax benefits as interest expense and penalties as other expense.

Idaho Power is subject to examination by its major tax jurisdictions - U.S. federal and the State of Idaho. The open tax years for examination are 2014 for federal and 2011-2014 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. In 2014, the IRS completed its examination of IDACORP's 2013 tax year with no unresolved income tax issues.

Tax Accounting Method Changes for Repair-Related Expenditures

In the fourth quarter of 2014, Idaho Power finalized an income tax accounting method change for its 2014 tax year associated with the electric generation property portion of its capitalized repairs tax method it adopted in fiscal year 2010. As a result of the change, Idaho Power recorded an $8.8 million tax benefit related to the cumulative method change adjustment for years prior to 2014 and reversed a related $4.6 million tax expense estimate it had recorded in 2013 (discussed below), for a total adjustment of $13.4 million.

The method change is pursuant to Revenue Procedure 2013-24 and will bring Idaho Power's existing method into alignment with the Revenue Procedure's safe harbor unit-of-property definitions for electric generation property. The change also incorporates provisions of the final tangible property regulations issued by the U.S. Treasury Department (Treasury) and IRS in the third quarter of 2013 that address the deduction or capitalization of expenditures related to tangible property. Following the automatic consent procedures provided for in the Revenue Procedure, Idaho Power expects to adopt this method with the filing of IDACORP's 2014 consolidated federal income tax return in September 2015. The method change will be subject to IRS review as part of IDACORP's CAP examination.

In the third quarter of 2014, Idaho Power, in coordination with the IRS through IDACORP's CAP examination process, implemented aspects of the final tangible property regulations and other technical interpretations of these rules into its existing capitalized repairs tax accounting method for generation, transmission and distribution assets. These technical interpretations were received from the IRS in 2014. An $11.1 million tax benefit related to the portion of the 2013 capitalized repairs deduction based on these modifications was recorded in the third quarter. Idaho Power finalized these changes with the filing of IDACORP's 2013 consolidated federal income tax return in September 2014. The IRS approved the repairs method modifications prior to the filing of the return as part of IDACORP's 2013 CAP examination.

In connection with the issuance of the tangible property regulations and following the provisions of Revenue Procedure 2013-24 (discussed above), in the third quarter of 2013 Idaho Power assessed and estimated the impact of a method change associated with the electric generation property portion of its capitalized repairs method. Based upon this assessment, in 2013 Idaho Power recorded $4.6 million of income tax expense related to the estimated cumulative method change adjustment for years prior to 2013.

The amount of the capitalized repairs 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, commonly referred to as "flow-through." A net regulatory asset is established to reflect Idaho Power's ability to recover the net increased income tax expense when such temporary differences reverse. Idaho Power's 2014 capitalized repairs deduction estimate incorporates the provisions of both method changes.

3. REGULATORY MATTERS

Included below is information on Idaho Power's regulatory assets and liabilities, as well as a summary of Idaho Power's most recent general rate changes and other notable recent or pending regulatory matters and proceedings.

Regulatory Assets and Liabilities

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 record such expenses and revenues. Regulatory assets represent incurred costs that have been deferred because it is probable they will be recovered from customers through future rates. Regulatory liabilities represent obligations to make refunds to customers for previous collections, or represent amounts collected in advance of incurring an expense. The following table presents a summary of Idaho Power's regulatory assets and liabilities (in thousands of dollars):

	Remaining Amortization Period	As of December 31, 2014 Earning a Return(1)	As of December 31, 2014 Not Earning a Return	Total as of December 31, 2014	Total as of December 31, 2013
Regulatory Assets:					
Income taxes		$ —	$ 802,188	$ 802,188	$ 710,482
Unfunded postretirement benefits(2)		—	264,548	264,548	116,583
Pension expense deferrals		40,816	22,828	63,644	75,108
Energy efficiency program costs(3)		4,690	—	4,690	3,694
Power supply costs(3)	Varies	59,189	—	59,189	91,477
Fixed cost adjustment(3)	2015-2016	23,737	—	23,737	19,526
Asset retirement obligations(4)		—	17,309	17,309	18,026
Mark-to-market liabilities(5)		—	3,961	3,961	1,629
Other	2015-2021	1,215	1,906	3,121	3,546
Total		$ 129,647	$ 1,112,740	$ 1,242,387	$ 1,040,071
Regulatory Liabilities:					
Income taxes		$ —	$ 55,490	$ 55,490	$ 55,017
Energy efficiency program costs(3)		—	—	—	6,686
Power supply costs(3)	Varies	1	—	1	24
Settlement agreement sharing mechanism(3)	2015-2016	7,999	—	7,999	7,602
Mark-to-market assets(5)		—	1,880	1,880	1,672
Other		3,114	922	4,036	3,470
Total		$ 11,114	$ 58,292	$ 69,406	$ 74,471

(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 in this Note 3.

(4) Asset retirement obligations 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 typically 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 materially adverse 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 contracted power purchase prices and volumes, changes in wholesale market prices and transaction volumes, fuel prices, and the levels of Idaho Power's own generation.

Idaho Jurisdiction Power Cost Adjustment Mechanism: In the Idaho jurisdiction, the annual PCA adjustment consists of (a) a forecast component, based on a forecast of net power supply costs in the coming year as compared with net power supply costs included 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 exceptions of expenses associated with PURPA power purchases and demand response incentive payments, which are allocated 100 percent to customers; and
- a load change adjustment rate, which is intended to ensure that power supply expense fluctuations resulting solely from load changes do not distort the results of the mechanism.

The table below summarizes the two most recent Idaho PCA rate adjustments, all of which also include non-PCA-related rate adjustments as ordered by the IPUC:

Effective Date	$ Change (millions)	Notes
June 1, 2014	$ (88.2)	2014 PCA rates are net of (a) $20.0 million of surplus Idaho energy efficiency rider funds, and (b) $7.6 million of customer revenue sharing under a regulatory settlement stipulation. In addition, on June 1, 2014, there was an increase in base net power supply costs that shifted $99.3 million in power supply expenses from recovery via the PCA mechanism to recovery via base rates. See further discussion of the change in base net power supply costs below.
June 1, 2013	$ 140.4	The 2013 PCA rate increase was net of $7.2 million of customer revenue sharing under regulatory settlement stipulations.

On November 1, 2013, Idaho Power filed an application with the IPUC requesting an increase of approximately $106 million in the normalized or "base level" net power supply expense on a total-system basis to be used to update base rates and in the determination of the PCA rate that would become effective June 1, 2014. Idaho Power's request was intended to remove the Idaho-jurisdictional portion of those expenses (approximately $99 million) from collection via the Idaho PCA mechanism and instead collect that portion through base rates. On March 21, 2014, the IPUC issued an order approving Idaho Power's application, with the change in collection methodology effective June 1, 2014.

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 Oregon-jurisdictional 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 2014 and 2013 are summarized in the table that follows:

Year and Mechanism	APCU or PCAM Adjustment
2014 PCAM	Idaho Power estimates that actual net power supply costs were within the deadband, which would result in no deferral.
2014 APCU	A rate increase of $0.4 million annually took effect June 1, 2014.
2013 PCAM	Actual net power supply costs were within the deadband, resulting in no deferral.
2013 APCU	A rate increase of $2.9 million annually took effect June 1, 2013.

Idaho Regulatory Matters

Idaho Base Rate Changes: Effective January 1, 2012, Idaho Power implemented new Idaho base rates resulting from IPUC approval of a settlement stipulation that provided for a 7.86 percent authorized overall rate of return on an Idaho-jurisdiction rate base of approximately $2.36 billion. The settlement stipulation resulted in a 4.07 percent, or $34.0 million, overall increase in Idaho Power's annual Idaho-jurisdiction base rate revenues. Idaho base rates were subsequently adjusted again in 2012, in connection with Idaho Power's completion of the Langley Gulch power plant. On June 29, 2012, the IPUC issued an order approving a $58.1 million increase in annual Idaho-jurisdiction base rates, effective July 1, 2012. The order also provided for a $335.9 million increase in Idaho rate base. Neither the settlement stipulation nor the IPUC orders adjusting base rates specified an authorized rate of return on equity or imposed a moratorium on Idaho Power filing a general rate case at a future date.

As noted above in this Note 3, the IPUC also issued a March 2014 order approving Idaho Power's request for an increase in the normalized or "base level" net power supply expense to be used to update base rates and in the determination of the Idaho PCA rate that would become effective June 1, 2014.

December 2011 Idaho Settlement Stipulation: On December 27, 2011, the IPUC issued an order, separate from the general rate case proceeding, approving a settlement stipulation that provided as follows:

- If Idaho Power's actual Idaho-jurisdiction return on year-end equity (Idaho ROE) for 2012, 2013, or 2014 is less than 9.5 percent, then Idaho Power may amortize up to a total of $45 million of additional ADITC to help achieve a minimum 9.5 percent Idaho ROE in the applicable year.

- If Idaho Power's actual Idaho ROE for 2012, 2013, or 2014 exceeds 10.0 percent, the amount of Idaho Power's Idaho-jurisdiction earnings exceeding a 10.0 percent and up to and including a 10.5 percent Idaho ROE for the applicable year would be shared equally between Idaho Power and its Idaho customers in the form of a rate reduction to become effective at the time of the subsequent year's PCA mechanism adjustment.
- 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 as a reduction to the pension regulatory asset and 25 percent to Idaho Power.

As Idaho Power's Idaho ROE exceeded 10.5 percent for 2013 and 2014, Idaho Power did not amortize additional ADITC for those years, but instead shared a portion of its Idaho-jurisdiction earnings with Idaho customers. The amounts Idaho Power recorded in 2013 and 2014 for sharing with customers under the December 2011 Idaho regulatory settlement stipulation were as follows (in millions):

Year	Recorded as Refunds to Customers	Recorded as a Pre-tax Charge to Pension Expense
2014	$8.0	$16.7
2013	$7.6	$16.5

October 2014 Idaho Settlement Stipulation: In October 2014, the IPUC issued an order approving an extension, with modifications, of the terms of the December 2011 Idaho settlement stipulation for the period from 2015 through 2019, or until the terms are otherwise modified or terminated by order of the IPUC or the full $45 million of additional ADITC contemplated by the settlement stipulation has been amortized. The provisions of the new settlement stipulation are as follows:

- If Idaho Power's annual Idaho ROE in any year is less than 9.5 percent, then Idaho Power may amortize up to $25 million of additional ADITC to help achieve a 9.5 percent Idaho ROE for that year, and may amortize up to a total of $45 million of additional ADITC over the 2015 through 2019 period.
- If Idaho Power's annual Idaho ROE in any year exceeds 10.0 percent, the amount of earnings exceeding a 10.0 percent Idaho ROE and up to and including a 10.5 percent Idaho ROE will be allocated 75 percent to Idaho Power's Idaho customers as a rate reduction to be effective at the time of the subsequent year's power cost adjustment and 25 percent to Idaho Power.
- If Idaho Power's annual Idaho ROE in any year exceeds 10.5 percent, the amount of earnings exceeding a 10.5 percent Idaho ROE will be allocated 50 percent to Idaho Power's Idaho customers as a rate reduction to be effective at the time of the subsequent year's power cost adjustment, 25 percent to Idaho Power's Idaho customers in the form of a reduction to the pension regulatory asset balancing account (to reduce the amount to be collected in the future from Idaho customers), and 25 percent to Idaho Power.
- If the full $45 million of additional ADITC contemplated by the settlement stipulation has been amortized the sharing provisions would terminate.
- In the event the IPUC approves a change to Idaho Power's Idaho-jurisdictional allowed return on equity as part of a general rate case proceeding seeking a rate change effective prior to January 1, 2020, the Idaho ROE thresholds (9.5 percent, 10.0 percent, and 10.5 percent) will be adjusted prospectively.

Neither the settlement stipulation nor the associated IPUC order impose a moratorium on Idaho Power filing a general rate case or other form of rate proceeding during the term of the settlement stipulation.

Fixed Cost Adjustment: The Idaho jurisdiction fixed cost adjustment (FCA) mechanism is designed to remove Idaho Power's financial 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 mechanism is adjusted each year to collect, or refund, the difference between the allowed fixed-cost recovery amount and the actual (weather-normalized) fixed costs recovered by Idaho Power during the year. The amount of the FCA recovery is capped at no more than 3 percent of base revenue, with any excess deferred for collection in a subsequent year. The following table summarizes FCA amounts approved for collection in the prior two FCA years:

FCA Year	Period Rates in Effect	Annual Amount (in millions)
2013	June 1, 2014-May 31, 2015	$14.9
2012	June 1, 2013-May 31, 2014	$8.9

On July 1, 2014, the IPUC opened a docket to allow Idaho Power, the IPUC Staff, and other interested parties to further evaluate the IPUC Staff's concerns regarding the application of the FCA mechanism. Concerns cited by interested parties included the application of weather-normalization, the customer count methodology, the rate adjustment cap, cross-subsidization issues, and whether the FCA mechanism is in fact effectively removing Idaho Power's disincentive to aggressively pursue energy efficiency programs. Proceedings in the FCA mechanism docket, which remains open, could result in significant changes to the FCA mechanism.

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. Typically, a majority of energy efficiency activities are funded through a rider mechanism on customer bills. Program expenditures are reported as an operating expense with an equal amount of revenues recorded in other revenues, resulting in no 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. The December 2011 IPUC general rate case settlement order described above 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. As of December 31, 2014, the Idaho energy efficiency rider balance was a regulatory asset of $0.8 million.

On June 12, 2013, the IPUC issued an order authorizing Idaho Power to recover custom efficiency program incentive payments, including the then-current regulatory asset balance of approximately $14 million, as well as subsequent custom efficiency program incentive payments, through the Idaho energy efficiency rider mechanism. As a result of the order, Idaho Power recognized the balance as other revenue and energy efficiency program expenses in 2013.

Oregon Regulatory Matters

Oregon Base Rate Changes: On February 23, 2012, the OPUC issued an order approving a settlement stipulation that provided for a $1.8 million base rate increase, a return on equity of 9.9 percent, and an overall rate of return of 7.757 percent in the Oregon jurisdiction. New rates in conformity with the settlement stipulation were effective March 1, 2012. Subsequently, on September 20, 2012, the OPUC issued an order approving an approximately $3.0 million increase in annual Oregon jurisdiction base rates, effective October 1, 2012, for inclusion of the Langley Gulch power plant in Idaho Power's Oregon rate base.

Federal Regulatory Matters - Open Access Transmission Tariff 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 primarily 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, 2014 to September 30, 2015	$ 22.71
October 1, 2013 to September 30, 2014	$ 22.80
October 1, 2012 to September 30, 2013	$ 21.32

Idaho Power's current OATT rate is based on a net annual transmission revenue requirement of $120.8 million, which represents the OATT formulaic determination of Idaho Power's net cost of providing OATT-based transmission service.

4. LONG-TERM DEBT

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

	2014	2013
First mortgage bonds:		
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
2.95% Series due 2022	75,000	75,000
2.50% Series due 2023	75,000	75,000
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
4.30% Series due 2042	75,000	75,000
4.00% Series due 2043	75,000	75,000
Total first mortgage bonds	1,425,000	1,425,000
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	3,191	4,255
Unamortized premium/discount - net	(3,034)	(3,278)
Total Idaho Power outstanding debt(2)	1,615,502	1,616,322
Current maturities of long-term debt	(1,064)	(1,064)
Total long-term debt	$ 1,614,438	$ 1,615,258

(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, 2014 to $1.591 billion.
(2) At December 31, 2014 and 2013, the overall effective cost of Idaho Power's outstanding debt was 5.19 percent.

At December 31, 2014, the maturities for the aggregate amount of Idaho Power long-term debt outstanding were as follows (in thousands of dollars):

2015	2016	2017	2018	2019	Thereafter
$ 1,064	$ 1,064	$ 1,064	$ 120,000	$ 100,000	$ 1,395,344

Long-Term Debt Issuances, Maturities, and Availability

On April 8, 2013, Idaho Power issued $75 million in principal amount of 2.50% first mortgage bonds, Series I, maturing on April 1, 2023, and $75 million in principal amount of 4.00% first mortgage bonds, Series I, maturing on April 1, 2043. On October 1, 2013, Idaho Power used a portion of the net proceeds of the April 2013 sale of first mortgage bonds to satisfy its obligations upon maturity of $70 million in principal amount of 4.25% first mortgage bonds.

In February 2013, Idaho Power filed applications with the IPUC, OPUC, and Wyoming Public Service Commission (WPSC) seeking authorization to issue and sell from time to time up to $500 million in aggregate principal amount of debt securities and first mortgage bonds. In April 2013, Idaho Power received orders from the IPUC, OPUC, and WPSC authorizing such issuance and sales, subject to conditions specified in the orders. The order from the IPUC approved the issuance of the securities through April 9, 2015, subject to extension upon request to the IPUC. The OPUC’s and WPSC’s orders do not impose a time limitation for issuances, but the OPUC order does impose a number of other conditions, including a maximum interest rate limit of 7 percent.

In anticipation of the expiration of the prior registration statement, on May 22, 2013, IDACORP and Idaho Power filed a joint shelf registration statement with the SEC, which became effective upon filing, for the offer and sale of, in the case of Idaho Power, an unspecified principal amount of its first mortgage bonds and debt securities. On July 12, 2013, Idaho Power entered into a Selling Agency Agreement with eight 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, secured medium term notes, Series J (Series J Notes), under Idaho Power’s Indenture of Mortgage and Deed of Trust, dated as of October 1, 1937, as amended and supplemented (Indenture). Also on July 12, 2013, Idaho Power entered into the Forty-seventh Supplemental Indenture, dated as of July 1, 2013, to the Indenture. The Forty-seventh Supplemental Indenture provides for, among other items, the issuance of up to $500 million in aggregate principal amount of Series J Notes pursuant to the Indenture. As of December 31, 2014, Idaho Power had not sold any first mortgage bonds, including Series J Notes, or debt securities under the Selling Agency Agreement.

***Mortgage*:** As of December 31, 2014, Idaho Power could issue under its Indenture approximately $1.6 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 Indenture.

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

On February 17, 2010, Idaho Power entered into the Forty-fifth Supplemental Indenture, dated as of February 1, 2010, to the Indenture for the purpose of increasing the maximum amount of first mortgage bonds issuable by Idaho Power from $1.5 billion to $2.0 billion. The amount issuable is also restricted by property, earnings, and other provisions of the Indenture and supplemental indentures to the Indenture. Idaho Power may amend the Indenture and increase this amount without consent of the holders of the first mortgage bonds. The Indenture requires that Idaho Power's net earnings 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

Idaho Power has in place a credit facility that 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, subject to certain conditions.

The interest rate 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 agreements. Under the credit facility, the company pays a facility fee on the commitment based on the company's credit rating for senior unsecured long-term debt securities. While the credit facility provided for an original termination date of October 26, 2016, the credit agreement granted Idaho Power the right to request up to two one-year extensions, in each case subject to certain conditions. In October 2012 and October 2013, Idaho Power executed agreements with the lenders, extending the maturity date under the credit agreement to October 26, 2018. No other terms of the credit facility, including the amount of permitted borrowings, were affected by the extensions.

At December 31, 2014, no loans were outstanding under Idaho Power's facility. At December 31, 2014, Idaho Power had regulatory authority to incur up to $450 million in principal amount of short-term indebtedness at any one time outstanding. Balances (in thousands of dollars) and interest rates of Idaho Power's short-term borrowings were as follows at December 31, 2014 and December 31, 2013:

	2014	2013
Commercial paper balances:		

At the end of year	$	—	$	—
Average during the year	$	—	$	2,209
Weighted-average interest rate				
At the end of the year		—%		—%

6. COMMON STOCK

Idaho Power Common Stock

No contributions were made to Idaho Power in 2014 or 2013, and no additional shares of Idaho Power common stock were issued.

Restrictions on Dividends

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 the credit facility or Idaho Power’s Revised Code of Conduct. 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. At December 31, 2014, the leverage ratio for Idaho Power was 47 percent. Based on these restrictions, Idaho Power’s dividends were limited to $944 million at December 31, 2014. There are additional facility covenants, subject to exceptions, that prohibit or restrict the sale or disposition of property without consent and any agreements restricting dividend payments to the company from any material subsidiary. At December 31, 2014, Idaho Power was in compliance with those covenants.

Idaho Power’s Revised Policy and Code of Conduct relating to transactions between and among Idaho Power, IDACORP, and other affiliates, which was approved by the IPUC in April 2008, provides 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. At December 31, 2014, Idaho Power's common equity capital was 53 percent of its total adjusted capital. Further, Idaho Power must obtain approval from 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. As of the date of this report, 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 account" is undefined in the Federal Power Act or its regulations, but Idaho Power does not believe the restriction would limit Idaho Power's ability to pay dividends out of current year earnings or retained earnings.

In accordance with Section 10(d) of the Federal Power Act, Idaho Power has $13.3 million of amortization reserves established for certain of its licensed hydroelectric facilities.

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 stock options, restricted stock, performance shares, and several other types of stock-based awards. The RSP (for officers and key employees) permits only the grant of restricted stock or performance-based restricted stock. At December 31, 2014, the maximum number of shares available under the LTICP and RSP were 1,166,210 and 15,796, respectively, excluding (i) issued but unvested performance-based restricted shares and (ii) issued but unvested time-based restricted shares.

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 closing 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 the attainment of specific performance conditions over the three-year vesting period. The performance conditions are two equally-weighted metrics, cumulative earnings per share (CEPS) and total shareholder return (TSR) relative to a peer group. Depending on the level of attainment of the performance conditions, the final number of shares awarded can range from zero to 150 percent of the target award. Dividends are accrued during the vesting period and paid out based on the final number of shares awarded.

The grant-date fair value of the CEPS portion is based on the closing market value at the date of grant, reduced by the loss in time-value of the estimated future dividend payments. The fair value of this portion of the awards is charged to compensation expense over the requisite service period, based on the number of shares expected to vest. The grant-date fair value of the TSR portion is estimated using the market value at the date of grant and a statistical model that incorporates the probability of meeting performance targets based on historical returns relative to the peer group. The fair value of this portion of the awards is charged to compensation expense over the requisite service period, provided the requisite service period is rendered, regardless of the level of TSR metric attained.

A summary of restricted stock and performance share activity is presented below. Share amounts represent the shares of IDACORP common stock:

	Number of Shares	**Weighted-Average Grant Date Fair Value**
Nonvested shares at January 1, 2014	305,984	$ 36.85
Shares granted	105,367	48.74
Shares forfeited	(35,298)	46.34
Shares vested	(125,657)	30.09
Nonvested shares at December 31, 2014	**250,396**	**$ 43.91**

The total fair value of shares vested during the years ended December 31, 2014 and 2013 was $6.6 million and $5.0 million, respectively. At December 31, 2014, Idaho Power had $4.6 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 1.69 years. IDACORP uses original issue and/or treasury shares for these awards.

In 2014, a total of 14,599 of IDACORP common stock shares were awarded to directors of IDACORP and Idaho Power at a grant date fair value of $56.05 per share. Directors elected to defer receipt of 8,004 of these shares, which are being held as deferred stock units with dividend equivalents reinvested in additional stock units.

Stock Options: IDACORP has not granted any stock option awards since 2006 and has no plans to do so in the future. At December 31, 2014, there were no outstanding options.

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):

	2014	2013
Compensation cost	$ 5,458	$ 4,783
Income tax benefit	2,134	1,870

No equity compensation costs have been capitalized.

8. COMMITMENTS

Purchase Obligations

At December 31, 2014, Idaho Power had the following long-term commitments relating to purchases of energy, capacity, transmission rights, and fuel (in thousands of dollars):

	2015	2016	2017	2018	2019	Thereafter
Cogeneration and power production	$ 181,468	$ 189,493	$ 229,255	$ 240,280	$ 238,501	$ 4,064,213
Power and transmission rights	6,370	5,416	3,337	1,199	1,105	4,487
Fuel	64,415	42,124	41,744	9,352	9,169	68,359

As of December 31, 2014, Idaho Power had 781 MW nameplate capacity of PURPA-related projects on-line, with an additional 521 MW nameplate capacity of projects projected to be on-line by June 1, 2017. The power purchase contracts for these projects have original contract terms ranging from one to 35 years. Idaho Power's expenses associated with PURPA-related projects were approximately $145 million in 2014 and $131 million in 2013.

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

	2015	2016	2017	2018	2019	Thereafter
Operating leases	$ 162	$ 1,039	$ 1,065	$ 1,088	$ 1,167	$ 14,136
Equipment, maintenance, and service agreements	61,492	19,610	8,279	7,794	7,978	31,489
FERC and other industry-related fees	12,954	6,813	6,813	6,813	6,813	34,063

Idaho Power's expense for operating leases was approximately $5.8 million in 2014 and $5.2 million in 2013.

Guarantees

Through a self-bonding mechanism, Idaho Power guarantees its portion of reclamation activities and obligations at BCC, of which IERCo owns a one-third interest. This guarantee, which is renewed annually with the Wyoming Department of Environmental Quality, was $70 million at December 31, 2014, representing IERCo's one-third share of BCC's total reclamation obligation. BCC has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. At December 31, 2014, the value of the reclamation trust fund was $67 million. During 2014 the reclamation trust fund distributed approximately $13 million for reclamation activity costs associated with the BCC surface mine. 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, all of which are made to the Jim Bridger plant. 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 historical experience and the evaluation of the specific indemnities. As of December 31, 2014, 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 within the consolidated balance sheet 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. 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, 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 loss contingencies are not material to the 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. For matters that affect Idaho Power’s operations, Idaho Power intends to seek, to the extent permissible and appropriate, recovery through the ratemaking process of costs incurred.

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. Idaho Power and IESCo (as successor to IDACORP Energy L.P.) believe that settlement releases they have obtained will restrict potential claims that might result from the disposition of pending proceedings and predict that these matters will not have a material adverse effect on Idaho Power's results of operations or financial condition. However, the settlements and associated FERC orders have not fully eliminated the potential for so-called "ripple claims," which involve potential claims for refunds in the Pacific Northwest markets from an upstream seller of power based on a finding that its downstream buyer was liable for refunds as a seller of power during the relevant period. The FERC has characterized these ripple claims as "speculative." However, the FERC has refused to dismiss Idaho Power and IESCo from the proceedings in the Pacific Northwest and refused to approve portions of two settlements that provided for waivers of claims in those proceedings, despite only limited objections from two market participants to one of the two settlements and no objections to the other settlement. Idaho Power and IESCo have petitions for review of the FERC's decisions refusing to approve the waiver provision of the settlements, on the basis that the FERC failed to apply its established precedents and rules. The petitions for review are pending in the Ninth Circuit Court of Appeals.

Based on its evaluation of the merits of ripple claims and the inability to estimate the potential exposure should the claims ultimately have any merit, particularly in light of Idaho Power and IESCo being both purchasers and sellers in the energy market during the relevant period, Idaho Power and IESCo have no amount accrued relating to the proceedings. To the extent the availability of any ripple claims materializes, Idaho Power and IESCo will continue to vigorously defend their positions in the proceedings.

Other Proceedings

Idaho Power is party to legal claims and legal and regulatory actions and proceedings in the ordinary course of business that are in addition to those discussed above and, as noted above, records an accrual for associated loss contingencies when they are probable and reasonably estimable. As of the date of this report the company believes that resolution of those matters will not have a material adverse effect on the consolidated financial statements. Idaho Power is also actively monitoring various pending environmental regulations, including the EPA's proposed rule under Section 111(d) of the Clean Air Act, that may have a significant impact on its future operations. Given uncertainties regarding the outcome, timing, and compliance plans for these environmental matters, Idaho Power is unable to estimate the financial impact of these regulations but does believe that future capital investment for infrastructure and modifications to its electric generating facilities to comply with these regulations could be significant.

10. BENEFIT PLANS

Idaho Power sponsors defined benefit and other postretirement benefit plans that cover the majority of its employees. Idaho Power also sponsors a defined contribution 401(k) employee savings plan and provides certain post-employment benefits.

Pension Plans

Idaho Power has two pension plans – a noncontributory defined benefit pension plan (pension plan) and a nonqualified defined benefit pension plan for certain senior management employees called the Security Plan for Senior Management Employees (SMSP). Idaho Power also has a nonqualified defined benefit pension plan for directors that was frozen in 2002. Remaining vested benefits from that plan are included with the SMSP in the disclosures below. The benefits under these plans are based on years of service and the employee's final average earnings.

Idaho Power’s funding policy for the pension plan is to contribute 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 2014 and

2013 Idaho Power elected to contribute more than the minimum required amounts in order to bring the pension plan to a more funded position, to reduce future required contributions, and to reduce Pension Benefit Guaranty Corporation premiums.

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

	Pension Plan 2014	**Pension Plan 2013**	**SMSP 2014**	**SMSP 2013**
Change in benefit obligation:				
Benefit obligation at January 1	$ 695,093	$ 767,692	$ 77,773	$ 80,515
Service cost	25,292	31,357	1,645	2,178
Interest cost	35,415	31,830	3,856	3,258
Actuarial loss (gain)	114,496	(112,215)	15,324	(4,663)
Benefits paid	(25,484)	(23,571)	(4,188)	(3,515)
Projected benefit obligation at December 31	844,812	695,093	94,410	77,773
Change in plan assets:				
Fair value at January 1	545,092	460,862	—	—
Actual return on plan assets	10,111	77,801	—	—
Employer contributions	30,000	30,000	—	—
Benefits paid	(25,484)	(23,571)	—	—
Fair value at December 31	559,719	545,092	—	—
Funded status at end of year	$ (285,093)	$ (150,001)	$ (94,410)	$ (77,773)
Amounts recognized in the statement of financial position consist of:				
Other current liabilities	$ —	$ —	$ (4,193)	$ (3,905)
Noncurrent liabilities	(285,093)	(150,001)	(90,217)	(73,868)
Net amount recognized	$ (285,093)	$ (150,001)	$ (94,410)	$ (77,773)
Amounts recognized in accumulated other comprehensive income consist of:				
Net loss	$ 263,350	$ 120,587	$ 38,808	$ 26,102
Prior service cost	295	642	857	1,077
Subtotal	263,645	121,229	39,665	27,179
Less amount recorded as regulatory asset	(263,645)	(121,229)	—	—
Net amount recognized in accumulated other comprehensive income	$ —	$ —	$ 39,665	$ 27,179
Accumulated benefit obligation	$ 719,617	$ 591,649	$ 84,684	$ 70,530

The actuarial loss affecting the change in projected benefit obligations from December 31, 2013 to December 31, 2014 is due to the reduction in the discount rates, as identified in the plan assumptions table included later in this footnote.

As a non-qualified plan, the SMSP has no plan assets. However, Idaho Power has a Rabbi trust designated to provide funding for SMSP obligations. The Rabbi trust holds investments in marketable securities and corporate-owned life insurance. The fair value of these investments was approximately $65.0 million and $59.2 million at December 31, 2014 and 2013, respectively, and is reflected in Investments and in Company-owned life insurance on the consolidated balance sheets.

The following table shows the components of net periodic benefit cost for these plans (in thousands of dollars). For purposes of calculating the expected return on plan assets, the market-related value of assets is equal to the fair value of the assets.

	Pension Plan 2014	**Pension Plan 2013**	**SMSP 2014**	**SMSP 2013**
Service cost	$ 25,292	$ 31,357	$ 1,645	$ 2,178

Interest cost	35,415	31,830	3,856	3,258
Expected return on plan assets	(42,289)	(35,755)	—	—
Amortization of net loss	3,911	17,118	2,618	2,840
Amortization of prior service cost	347	347	220	212
Net periodic pension cost	22,676	44,897	8,339	8,488
Adjustments due to the effects of regulation[1]	12,124	(9,013)	—	—
Net periodic benefit cost recognized for financial reporting	$ 34,800	$ 35,884	$ 8,339	$ 8,488

[1] Net periodic benefit costs for the pension plan are recognized for financial reporting based upon the authorization of each regulatory jurisdiction in which Idaho Power operates. Under IPUC order, income statement recognition of pension plan costs is deferred until costs are recovered through rates.

The following table shows the components of other comprehensive income for the plans (in thousands of dollars):

	Pension Plan 2014	Pension Plan 2013	SMSP 2014	SMSP 2013
Actuarial (loss) gain during the year	$ (146,674)	$ 154,261	$ (15,324)	$ 4,664
Reclassification adjustments for:				
Amortization of net loss	3,911	17,118	2,618	2,840
Amortization of prior service cost	347	347	220	212
Adjustment for deferred tax effects	55,678	(67,136)	4,881	(3,017)
Adjustment due to the effects of regulation	86,738	(104,590)	—	—
Other comprehensive income recognized related to pension benefit plans	$ —	$ —	$ (7,605)	$ 4,699

In 2015, Idaho Power expects to recognize as components of net periodic benefit cost $18.8 million from amortizing amounts recorded in accumulated other comprehensive income (or as a regulatory asset for the pension plan) as of December 31, 2014, relating to the pension plan and SMSP. This amount consists of $14.2 million of amortization of net loss and $0.2 million of amortization of prior service cost for the pension plan, and $4.2 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):

	2015	2016	2017	2018	2019	2020-2024
Pension Plan	$ 27,634	$ 29,938	$ 32,428	$ 35,036	$ 37,644	$ 226,411
SMSP	4,274	4,198	4,262	4,134	4,291	23,868

As of December 31, 2014, Idaho Power's minimum required contribution to the pension plan is estimated to be zero in 2015, though Idaho Power plans to contribute at least $20 million to the pension plan during 2015.

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-employee 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):

	2014	2013
Change in accumulated benefit obligation:		
Benefit obligation at January 1	$ 57,341	$ 72,547
Service cost	1,011	1,315
Interest cost	2,841	2,633
Actuarial loss (gain)	7,026	(16,788)
Benefits paid[1]	(2,220)	(2,366)
Benefit obligation at December 31	65,999	57,341
Change in plan assets:		
Fair value of plan assets at January 1	37,111	33,387
Actual return on plan assets	3,888	6,212
Employer contributions[1]	(404)	(122)
Benefits paid[1]	(2,220)	(2,366)
Fair value of plan assets at December 31	38,375	37,111
Funded status at end of year (included in noncurrent liabilities)	$ (27,624)	$ (20,230)

(1) Contributions and benefits paid are each net of $3,379 thousand and $3,272 thousand of plan participant contributions, and $344 thousand and $372 thousand of Medicare Part D subsidy receipts for 2014 and 2013, respectively.

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

	2014	2013
Net loss	$ 759	$ (4,974)
Prior service cost	145	328
Subtotal	904	(4,646)
Less amount recognized in regulatory assets	(904)	4,646
Net amount recognized in accumulated other comprehensive income	$ —	$ —

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

	2014	2013
Service cost	$ 1,011	$ 1,315
Interest cost	2,841	2,633
Expected return on plan assets	(2,595)	(2,328)
Amortization of net loss	—	98
Amortization of prior service cost	183	(229)
Amortization of unrecogznied transition obligation	—	—
Net periodic postretirement benefit cost	$ 1,440	$ 1,489

The following table shows the components of other comprehensive income for the plan (in thousands of dollars):

	2014	2013
Actuarial (loss) gain during the year	$ (5,733)	$ 20,673
Reclassification adjustments for:		
Amortization of net loss	—	98

Amortization of prior service cost	183	(229)
Adjustment for deferred tax effects	2,170	(8,031)
Adjustment due to the effects of regulation	3,380	(12,511)
Other comprehensive income related to postretirement benefit plans	$ —	$ —

In 2015, Idaho Power expects to recognize as a component of net periodic benefit cost $15 thousand from amortizing amounts recorded in accumulated other comprehensive income as of December 31, 2014, relating to the postretirement benefit plan. The entire amount represents $15 thousand of amortization of prior service cost.

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 under Medicare Part D, 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):

	2015	2016	2017	2018	2019	2020-2024
Expected benefit payments	$ 3,970	$ 4,040	$ 4,090	$ 4,160	$ 4,210	$ 21,310
Expected Medicare Part D subsidy receipts	390	430	470	520	560	3,560

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	Pension Plan	SMSP	SMSP	Postretirement Benefits	Postretirement Benefits
	2014	2013	2014	2013	2014	2013
Discount rate	4.25 %	5.20 %	4.20 %	5.10 %	4.20 %	5.15 %
Rate of compensation increase(1)	4.30 %	4.38 %	4.50 %	4.50 %	—	—
Medical trend rate	—	—	—	—	6.4 %	6.8 %
Dental trend rate	—	—	—	—	5.0 %	5.0 %
Measurement date	12/31/2014	12/31/2013	12/31/2014	12/31/2013	12/31/2014	12/31/2013

(1) The 2014 rate of compensation increase assumption for the pension plan includes an inflation component of 2.75% plus a 1.55% 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 their 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	Pension Plan	SMSP	SMSP	Postretiremen t Benefits	Postretiremen t Benefits
	2014	2013	2014	2013	2014	2013
Discount rate	5.20 %	4.20 %	5.10 %	4.15 %	5.15 %	4.20 %
Expected long-term rate of return on assets	7.75 %	7.75 %	—	—	7.25 %	7.25 %
Rate of compensation increase	4.30 %	4.38 %	4.50 %	4.50 %	—	—

Medical trend rate	—	—	—	—	6.4 %	6.8 %
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 6.4 percent in 2014 and is assumed to decrease gradually to 5.1 percent by 2093. The assumed dental cost trend rate used to measure the expected cost of dental benefits covered by the plan was 5.0 percent for all years. A one percentage point change in the assumed health care cost trend rate would have the following effects at December 31, 2014 (in thousands of dollars):

	One-Percentage-Point Increase	One-Percentage-Point Decrease
Effect on total of cost components	$ 325	$ (241)
Effect on accumulated postretirement benefit obligation	3,426	(2,657)

Plan Assets

Pension Asset Allocation Policy: The target allocation and actual allocations at December 31, 2014 for the pension asset portfolio by asset class is set forth below:

Asset Class	Target Allocation	Actual Allocation December 31, 2014
Debt securities	24 %	24 %
Equity securities	54 %	55 %
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 yield on the Moody's AA Corporate Bond Index. This historical risk premium is then added to the current yield on the Moody's AA Corporate Bond Index. 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 three-level fair value hierarchy described in Note 15. The following table presents the fair value of the plans' investments by asset category (in thousands of dollars). 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.

	Level 1	Level 2	Level 3	Total
Assets at December 31, 2014				
Pension plan assets:				
Cash and cash equivalents	$ 19,190	$ —	$ —	$ 19,190
Short-term bonds	—	10,991	—	10,991
Intermediate bonds	—	101,867	—	101,867
Long-term bonds	—	21,615	—	21,615
Equity Securities: Large-Cap	66,151	—	—	66,151
Equity Securities: Mid-Cap	68,974	—	—	68,974
Equity Securities: Small-Cap	50,972	—	—	50,972
Equity Securities: Micro-Cap	22,962	—	—	22,962
Equity Securities: International	6,555	57,705	—	64,260
Equity Securities: Emerging Markets	8,629	22,915	—	31,544
Real estate	—	—	33,996	33,996
Private market investments	—	—	37,118	37,118
Commodities funds	—	30,079	—	30,079
Total pension assets	$ 243,433	$ 245,172	$ 71,114	$ 559,719
Postretirement plan assets(1)	$ 11	$ 38,364	$ —	$ 38,375
Assets at December 31, 2013				
Pension plan assets:				
Cash and cash equivalents	$ 33,030	$ —	$ —	$ 33,030
Short-term bonds	—	11,068	—	11,068
Intermediate bonds	—	76,312	—	76,312
Long-term bonds	—	19,024	—	19,024
Equity Securities: Large-Cap	71,042	—	—	71,042
Equity Securities: Mid-Cap	23,346	23,112	—	46,458

Equity Securities: Small-Cap		48,998		—		—		48,998
Equity Securities: Micro-Cap		24,687		—		—		24,687
Equity Securities: International		19,128		74,908		—		94,036
Equity Securities: Emerging Markets		3,523		22,107		—		25,630
Equity Securities: Market Neutral		3,870		—		—		3,870
Real estate		—		—		28,019		28,019
Private market investments		—		—		33,709		33,709
Commodities funds		—		29,209		—		29,209
Total pension assets	$	227,624	$	255,740	$	61,728	$	545,092
Postretirement plan assets[1]	$	75	$	37,036	$	—	$	37,111

[1] The postretirement benefits assets are primarily life insurance contracts.

For the year ended December 31, 2014, the only significant transfer in and out of Levels 1, 2, or 3 was $23.1 million of mid-cap equity security investments that were transferred from Level 2 to Level 1. For the year ended December 31, 2013, there were no significant transfers into or out of Levels 1, 2, or 3.

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

		Private Equity		**Real Estate**		**Total**
Beginning balance - January 1, 2013	$	30,507	$	27,874	$	58,381
Realized gains		—		739		739
Unrealized gains		2,941		1,579		4,520
Purchases		89		4,726		4,815
Sales		—		(6,899)		(6,899)
Settlements		172		—		172
Ending balance - December 31, 2013		33,709		28,019		61,728
Realized gains		1,430		866		2,296
Unrealized (losses) gains		(545)		1,305		760
Purchases		2,434		3,806		6,240
Settlements		90		—		90
Ending balance - December 31, 2014	$	37,118	$	33,996	$	71,114

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 2 Postretirement Assets: These assets represent an investment in a life insurance contract and are recorded at fair value, which is the cash surrender value, less any unpaid expenses. The cash surrender value of this insurance contract is contractually equal to the insurance contract's proportionate share of the market value of an associated investment account held by the insurer. The investments held by the insurer's investment account are all instruments traded on exchanges with readily determinable market prices.

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.

The fair value of the Level 3 assets is determined based on pricing provided or reviewed by third-party vendors to our investment managers. While the input amounts used by the pricing vendors in determining fair value are not provided, and therefore unavailable for Idaho Power's review, the asset results are reviewed and monitored to ensure the fair values are reasonable and in line with market experience in similar assets classes. Additionally, the audited financial statements of the funds are reviewed at the time they are issued.

Employee Savings Plan

Idaho Power has a defined contribution plan designed to comply with Section 401(k) of the Internal Revenue Code and that covers substantially all employees. Idaho Power matches specified percentages of employee contributions to the plan. Matching annual contributions were approximately $7 million each year for 2013 and 2014.

Post-employment Benefits

Idaho Power provides certain benefits to former or inactive employees, their beneficiaries, and covered dependents after employment but before retirement, in addition to the health care benefits required under the Consolidated Omnibus Budget Reconciliation Act. 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, 2014 and 2013 is $2.0 million and $1.9 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 2014 and 2013 (in thousands of dollars):

	2014 Balance	2014 Avg Rate	2013 Balance	2013 Avg Rate
Production	$ 2,316,941	2.48 %	$ 2,272,381	2.47 %
Transmission	1,016,207	2.03 %	974,697	2.01 %
Distribution	1,516,933	2.72 %	1,459,666	2.72 %
General and Other	398,131	5.49 %	373,658	5.91 %
Total in service	5,248,212	2.68 %	5,080,402	2.69 %
Accumulated provision for depreciation	(2,021,074)		(1,940,654)	
In service - net	$ 3,227,138		$ 3,139,748	

Idaho Power's ownership interest in three jointly-owned generating facilities is included in the table above. Under the joint operating agreements for these facilities, each participating utility is responsible for financing its share of construction, operating, and leasing costs. Idaho Power's proportionate share of operating expenses for each facility is included in the Consolidated Statements of Income. These jointly-owned facilities, including balance sheet amounts and the extent of Idaho Power's participation, were as follows at December 31, 2014 (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	$ 569,220	$ 59,394	$ 293,432	33	771
Boardman	Boardman, OR	80,951	125	60,031	10	64
Valmy Units 1 and 2	Winnemucca, NV	372,791	19,023	193,756	50	284

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

IERCo, Idaho Power's wholly-owned subsidiary, is a joint venture in BCC. Idaho Power's coal purchases from the joint venture were $79 million in 2014 and 2013.

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 each year for 2013 and 2014.

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 estimated settlement 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 the IPUC. The regulatory assets recorded under this order do not earn a return on investment. Beginning June 1, 2012, accretion, depreciation, and gains or losses related to the Boardman generating facility have been exempted from such regulatory treatment as Idaho Power is now collecting amounts related to the decommissioning of Boardman in rates.

Idaho Power's recorded AROs relate to the removal of polychlorinated biphenyl-contaminated equipment at its distribution facilities and the reclamation and removal costs at its jointly-owned coal-fired generation facilities. In 2014, changes in estimates at its distribution facilities and at the coal-fired generation facilities resulted in a net decrease of $4.1 million in the recorded AROs. The decrease in the AROs in 2014 is primarily due to decreases in estimated future costs related to evaporation ponds at the Valmy generating facility.

Idaho Power also has additional AROs associated with its transmission system, hydroelectric facilities, natural gas-fired generation 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 following table presents the changes in the carrying amount of AROs (in thousands of dollars):

	2014	2013
Balance at beginning of year	$ 25,765	$ 22,982
Accretion expense	1,061	1,041
Revisions in estimated cash flows	(4,140)	2,722
Liability settled	(756)	(980)
Balance at end of year	$ 21,930	$ 25,765

13. INVESTMENTS

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

	2014	2013
Idaho Power investments:		
IERCo	$ 83,477	$ 91,385
Available-for-sale equity securities	44,942	41,119
Executive deferred compensation plan investments	141	1,153
Other investments	1	1
Total Idaho Power investments	128,561	133,658

Investments in Equity Securities

Investments in securities classified as available-for-sale securities are reported at fair value. Any unrealized gains or losses on available-for-sale securities are included in income, as the fair value option has been elected for these instruments. Unrealized gains and losses on available-for-sale securities were immaterial at December 31, 2014 and December 31, 2013.

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

	2014	2013
Proceeds from sales	$ —	$ 25,661
Gross realized gains from sales	—	11,637
Gross realized losses from sales	—	—

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, 2014 and December 31, 2013, there were no indicators of other-than-temporary impairment related to Idaho Power's investments.

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 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 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.

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. Idaho Power offsets fair value amounts recognized on its balance sheet and applies collateral related to derivative instruments executed with the same counterparty under the same master netting agreement. Idaho Power does not offset a counterparty's current derivative contracts with the counterparty's long-term derivative contracts, although Idaho Power's master netting arrangements would allow current and long-term positions to be offset in the event of default. Also, in the event of default, Idaho Power's master netting arrangements would allow for the offsetting of all transactions executed under the master netting arrangement. These types of transactions may include non-derivative instruments, derivatives qualifying for scope exceptions, receivables and payables arising from settled positions, and other forms of non-cash collateral (such as letters of credit). These types of transactions are excluded from the offsetting presented in the derivative fair value and offsetting table below.

The table below presents the gains and losses on derivatives not designated as hedging instruments for the years ended December 31, 2014 and 2013 (in thousands of dollars):

Location of Realized Gain/(Loss) on Derivatives Recognized in Income	Gain/(Loss on Derivatives Recognized in Income(1) 2014	Gain/(Loss on Derivatives Recognized in Income(1) 2013

Financial swaps	Off-system sales	$ (4,119)	$ (2,637)
Financial swaps	Purchased power	(1,416)	947
Financial swaps	Fuel expense	3,862	731
Financial swaps	Other operations and maintenance	(158)	35
Forward contracts	Off-system sales	277	185
Forward contracts	Purchased power	(279)	(196)
Forward contracts	Fuel expense	94	217

(1) Excludes unrealized gains or losses on 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 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.

Derivative Instrument Summary

The table below presents the fair values and locations of derivative instruments not designated as hedging instruments recorded on the balance sheets and reconciles the gross amounts of derivatives recognized as assets and as liabilities to the net amounts presented in the balance sheets at December 31, 2014 and 2013 (in thousands of dollars):

	Balance Sheet Location	Asset Derivatives Gross Fair Value	Asset Derivatives Amounts Offset	Asset Derivatives Net Assets
December 31, 2014				
Current:				
Financial swaps	Other current assets	$ 2,509	$ (2,002)(1)	$ 507
Financial swaps	Other current liabilities	379	(379)	—
Forward contracts	Other current assets	64	—	64
Forward contracts	Other current liabilities	—	—	—
Long-term:				
Forward contracts	Other assets	63	—	63
Total		$ 3,015	$ (2,381)	$ 634
December 31, 2013				
Current:				
Financial swaps	Other current assets	$ 1,451	$ (175)	$ 1,276
Financial swaps	Other current liabilities	373	(373)	0
Forward contracts	Other current assets	109	—	109
Forward contracts	Other current liabilities	—	—	0
Long-term:				
Financial swaps	Other assets	189	(28)	161
Forward contracts	Other assets	126	—	126
Total		$ 2,248	$ (576)	$ 1,672

	Balance Sheet Location	Liability Derivatives Gross Fair Value	Liability Derivatives Amounts Offset	Liability Derivatives Net Assets
December 31, 2014				
Current:				

Financial swaps	Other current assets	$	756	$	(756)	$	—
Financial swaps	Other current liabilities		4,335		(379)		3,956
Forward contracts	Other current assets		—		—		—
Forward contracts	Other current liabilities		5		—		5
Long-term:							
Forward contracts	Other assets		—		—		—
Total		$	5,096	$	(1,135)	$	3,961
December 31, 2013							
Current:							
Financial swaps	Other current assets	$	175	$	(175)	$	—
Financial swaps	Other current liabilities		1,975		(1,429)(1)		546
Forward contracts	Other current assets		—		—		—
Forward contracts	Other current liabilities		26		—		26
Long-term:							
Financial swaps	Other assets		28		(28)		—
Forward contracts	Other assets		—		—		—
Total		$	2,204	$	(1,632)	$	572

(1) Current asset and current liability derivative amounts offset include $1.2 million and $1.1 million of collateral payable and receivable for the periods ending December 31, 2014 and 2013, respectively.

The table below presents the volumes of derivative commodity forward contracts and swaps outstanding at December 31, 2014 and 2013 (in thousands of units):

Commodity	Units	December 31, 2014	December 31, 2013
Electricity purchases	MWh	115	89
Electricity sales	MWh	238	603
Natural gas purchases	MMBtu	6,913	10,804
Natural gas sales	MMBtu	409	555
Diesel purchases	Gallons	243	906

Credit Risk

At December 31, 2014, Idaho Power did not have material credit risk 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 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 commonly under Western Systems Power Pool agreements, physical gas contracts are usually under North American Energy Standards Board contracts, and financial transactions are usually under International Swaps and Derivatives Association, Inc. contracts. These contracts 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, 2014, was $5.1 million. Idaho Power posted no cash collateral related to this amount. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2014, Idaho Power would have been required to post an additional $5.9 million of cash collateral to its counterparties.

15. FAIR VALUE MEASUREMENTS

Idaho Power has categorized its 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 Idaho Power has the ability to access.

- Level 2: Financial assets and liabilities whose values are based on the following:
  a) quoted prices for similar assets or liabilities in active markets;
  b) quoted prices for identical or similar assets or liabilities in non-active markets;
  c) pricing models whose inputs are observable for substantially the full term of the asset or liability; 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 assessment of a particular input's significance 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. An item recorded at fair value is reclassified among levels when changes in the nature of valuation inputs cause the item to no longer meet the criteria for the level in which it was previously categorized. There were no transfers between levels or material changes in valuation techniques or inputs during the years ended December 31, 2014 and 2013.

The following table presents information about Idaho Power’s assets and liabilities measured at fair value on a recurring basis as of December 31, 2014 and 2013 (in thousands of dollars):

	December 31, 2014				December 31, 2013			
	Level 1	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets:								

Derivatives	$ 506	$ 128	$ —	$ 634	$ 1,437	$ 235	$ —	$ 1,672
Money market funds	100	—	—	100	100	—	—	100
Trading securities: Equity securities	141	—	—	141	1,153	—	—	1,153
Available-for-sale securities: Equity securities	44,942	—	—	44,942	41,119	—	—	41,119
Liabilities:								
Derivatives	$ 17	$ 3,944	$ —	$ 3,961	$ 546	$ 26	$ —	$ 572

Idaho Power's derivatives are contracts entered into as part of its management of loads and resources. Electricity derivatives are valued on the Intercontinental Exchange (ICE) with quoted prices in an active market. Natural gas and diesel derivative valuations are performed using New York Mercantile Exchange (NYMEX) and ICE pricing, adjusted for location basis, which are also quoted under NYMEX and ICE pricing. 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 the carrying value and estimated fair value of financial instruments that are not reported at fair value, as of December 31, 2014 and 2013, using available market information and appropriate valuation methodologies (in thousands of dollars):

	December 31, 2014		**December 31, 2013**	
	Carrying Amount	**Estimated Fair Value**	**Carrying Amount**	**Estimated Fair Value**
Liabilities:				
Long-term debt(1)	$ 1,615,502	$ 1,788,197	$ 1,616,322	$ 1,600,248

(1) Long-term debt is categorized as Level 2 within the fair value hierarchy, as defined earlier in this Note 15.

Long-term debt is not traded on an exchange and is valued using quoted rates for similar debt in active markets. Carrying values for cash and cash equivalents, deposits, customer and other receivables, notes payable, accounts payable, interest accrued, and taxes accrued approximate fair value.

16. CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME

Comprehensive income includes net income, unrealized holding gains and losses on available-for-sale marketable securities, and amounts related to the SMSP. The table below presents changes in components of accumulated other comprehensive income (AOCI), net of tax, during the years ended December 31, 2014 and 2013 (in thousands of dollars). Items in parentheses indicate reductions to AOCI.

	Unrealized Gains and Losses on Available-for-Sale Securities	**Defined Benefit Pension Items**	**Total**
December 31, 2014			
Balance at beginning of period	$ —	$ (16,553)	$ (16,553)
Other comprehensive income before reclassifications	—	(9,333)	(9,333)
Amounts reclassified from AOCI	—	1,728	1,728
Net current-period other comprehensive income	—	(7,605)	(7,605)

Balance at end of period	$ —	$ (24,158)	$ (24,158)
December 31, 2013			
Balance at beginning of period	$ 4,136	$ (21,252)	$ (17,116)
Other comprehensive income before reclassifications	2,951	2,840	5,791
Amounts reclassified from AOCI	(7,087)	1,859	(5,228)
Net current-period other comprehensive income	(4,136)	4,699	563
Balance at end of period	$ —	$ (16,553)	$ (16,553)

The table below presents amounts reclassified out of components of AOCI and the income statement location of those amounts reclassified during the years ended December 31, 2014 and 2013 (in thousands of dollars). Items in parentheses indicate increases to net income.

	Amount Reclassified from AOCI 2014	**Amount Reclassified from AOCI 2013**
Unrealized gains on available-for-sale securities		
Realized gain on sale of securities, before tax(1)	$ —	$ (11,637)
Tax benefit(2)	—	4,550
Net of tax	—	(7,087)
Amortization of defined benefit pension items(3)		
Prior service cost	220	212
Net loss	2,618	2,839
Total before tax	2,838	3,051
Tax benefit(2)	(1,110)	(1,192)
Net of tax	1,728	1,859
Total reclassification for the period	$ 1,728	$ (5,228)

(1) The realized gain is included in Idaho Power's consolidated income statement in other income (expense), net.

(2) The tax benefit is included in income tax expense (benefit) in the consolidated income statement of Idaho Power.

(3) Amortization of these items is included in Idaho Power's consolidated income statement in other expense, net.

17. RELATED PARTY TRANSACTIONS

IDACORP: Idaho Power performs corporate functions such as financial, legal, and management services for IDACORP and its subsidiaries. Idaho Power charges IDACORP for the costs of these services based on service agreements and other specifically identified costs. For these services Idaho Power billed IDACORP $1.4 million in 2014 and $1.0 million in 2013.

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 to Ida-West in each year for 2013 and 2014.

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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	4,136,553			(21,252,222)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income	(7,087,026)			1,858,601
3	Preceding Quarter/Year to Date Changes in Fair Value	2,950,473			2,840,246
4	Total (lines 2 and 3)	(4,136,553)			4,698,847
5	Balance of Account 219 at End of Preceding Quarter/Year				(16,553,375)
6	Balance of Account 219 at Beginning of Current Year				(16,553,375)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				1,728,379
8	Current Quarter/Year to Date Changes in Fair Value				(9,333,003)
9	Total (lines 7 and 8)				(7,604,624)
10	Balance of Account 219 at End of Current Quarter/Year				(24,157,999)

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			(17,115,669)		
2			(5,228,425)		
3			5,790,719		
4			562,294	176,741,143	177,303,437
5			(16,553,375)		
6			(16,553,375)		
7			1,728,379		
8			(9,333,003)		
9			(7,604,624)	189,386,993	181,782,369
10			(24,157,999)		

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	04/15/2015	End of 2014/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)	5,248,212,331	5,248,212,331
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	5,248,212,331	5,248,212,331
9	Leased to Others		
10	Held for Future Use	7,090,431	7,090,431
11	Construction Work in Progress	401,929,509	401,929,509
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	5,657,232,271	5,657,232,271
14	Accum Prov for Depr, Amort, & Depl	2,021,073,827	2,021,073,827
15	Net Utility Plant (13 less 14)	3,636,158,444	3,636,158,444
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	1,997,908,418	1,997,908,418
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	23,165,409	23,165,409
22	Total In Service (18 thru 21)	2,021,073,827	2,021,073,827
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		
33	Total Accum Prov (equals 14) (22,26,30,31,32)	2,021,073,827	2,021,073,827

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	04/15/2015	End of 2014/Q4

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
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					31
					32
					33

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
			2
			3
			4
			5
			6
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			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/Q4

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

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	5,703	
3	(302) Franchises and Consents	29,492,883	-196,102
4	(303) Miscellaneous Intangible Plant	32,001,618	2,704,134
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	61,500,204	2,508,032
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,707,109	5,099
9	(311) Structures and Improvements	147,607,746	5,720,605
10	(312) Boiler Plant Equipment	574,685,386	30,968,367
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	157,130,004	2,456,602
13	(315) Accessory Electric Equipment	69,526,524	625,133
14	(316) Misc. Power Plant Equipment	16,424,380	535,355
15	(317) Asset Retirement Costs for Steam Production	10,045,806	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	977,126,955	40,311,161
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	30,921,432	267,825
28	(331) Structures and Improvements	172,021,110	3,009,623
29	(332) Reservoirs, Dams, and Waterways	253,221,758	9,357,143
30	(333) Water Wheels, Turbines, and Generators	201,680,871	5,615,318
31	(334) Accessory Electric Equipment	52,291,611	4,995,191
32	(335) Misc. Power PLant Equipment	21,004,289	812,228
33	(336) Roads, Railroads, and Bridges	8,183,435	1,401,205
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	739,324,506	25,458,533
36	D. Other Production Plant		
37	(340) Land and Land Rights	2,690,006	
38	(341) Structures and Improvements	133,753,938	7,148,416
39	(342) Fuel Holders, Products, and Accessories	7,982,028	2,470,519
40	(343) Prime Movers	236,639,588	4,939,595
41	(344) Generators	73,353,524	-6,998,268
42	(345) Accessory Electric Equipment	95,671,190	-7,063,625
43	(346) Misc. Power Plant Equipment	5,839,469	407,924
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	555,929,743	904,561
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	2,272,381,204	66,674,255

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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	36,087,730	102,069
49	(352) Structures and Improvements	70,075,081	2,716,121
50	(353) Station Equipment	388,935,103	13,971,575
51	(354) Towers and Fixtures	162,004,612	6,341,023
52	(355) Poles and Fixtures	129,115,202	14,311,741
53	(356) Overhead Conductors and Devices	188,088,876	9,279,054
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices		
56	(359) Roads and Trails	390,266	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	974,696,870	46,721,583
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	4,859,147	316,069
61	(361) Structures and Improvements	32,820,611	913,719
62	(362) Station Equipment	196,765,816	5,794,037
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	235,549,416	7,425,968
65	(365) Overhead Conductors and Devices	126,034,768	3,619,432
66	(366) Underground Conduit	46,289,611	1,157,996
67	(367) Underground Conductors and Devices	207,476,280	12,302,488
68	(368) Line Transformers	471,882,211	28,734,467
69	(369) Services	56,858,427	1,369,592
70	(370) Meters	73,143,443	7,766,427
71	(371) Installations on Customer Premises	2,901,563	94,180
72	(372) Leased Property on Customer Premises	-38,361	2,302
73	(373) Street Lighting and Signal Systems	4,588,849	
74	(374) Asset Retirement Costs for Distribution Plant	533,712	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,459,665,493	69,496,677
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	16,579,675	-4,824
87	(390) Structures and Improvements	102,938,584	4,701,008
88	(391) Office Furniture and Equipment	40,898,058	7,308,118
89	(392) Transportation Equipment	67,727,230	6,807,324
90	(393) Stores Equipment	1,908,757	45,847
91	(394) Tools, Shop and Garage Equipment	7,196,937	616,301
92	(395) Laboratory Equipment	12,444,681	806,460
93	(396) Power Operated Equipment	12,801,276	1,136,844
94	(397) Communication Equipment	43,926,012	12,801,448
95	(398) Miscellaneous Equipment	5,736,818	265,832
96	SUBTOTAL (Enter Total of lines 86 thru 95)	312,158,028	34,484,358
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)	312,158,028	34,484,358
100	TOTAL (Accounts 101 and 106)	5,080,401,799	219,884,905
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)	5,080,401,799	219,884,905

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
			29,296,781		3
5,078,245			29,627,507		4
5,078,245			58,929,991		5
					6
					7
			1,712,208		8
3,243,987			150,084,364		9
10,490,606			595,163,147		10
					11
249,879			159,336,727		12
108,610			70,043,047		13
1,024,920			15,934,815		14
	-3,673,688		6,372,118		15
15,118,002	-3,673,688		998,646,426		16
					17
					18
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		-916	31,188,341		27
28,310			175,002,423		28
			262,578,901		29
105,628			207,190,561		30
458,911			56,827,891		31
46,595			21,769,922		32
			9,584,640		33
					34
639,444		-916	764,142,679		35
					36
			2,690,006		37
			140,902,354		38
			10,452,547		39
2,682,736			238,896,447		40
			66,355,256		41
			88,607,565		42
			6,247,393		43
					44
2,682,736			554,151,568		45
18,440,182	-3,673,688	-916	2,316,940,673		46

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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
40,945		-2,730	36,146,124		48
68,593		15,382	72,737,991		49
3,103,709		-15,001	399,787,968		50
158,783			168,186,852		51
829,288			142,597,655		52
1,007,330			196,360,600		53
					54
					55
			390,266		56
					57
5,208,648		-2,349	1,016,207,456		58
					59
		-85	5,175,131		60
34,476		16,845	33,716,699		61
497,312		-32,341	202,030,200		62
					63
1,887,005			241,088,379		64
1,646,176			128,008,024		65
153,281			47,294,326		66
1,122,161			218,656,607		67
6,001,802			494,614,876		68
360,634			57,867,385		69
381,296			80,528,574		70
64,373		-16,845	2,914,525		71
48,289			-84,348		72
			4,588,849		73
			533,712		74
12,196,805		-32,426	1,516,932,939		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
		3,731	16,578,582		86
585,872		-15,382	107,038,338		87
2,303,414			45,902,762		88
320,179			74,214,375		89
18,207			1,936,397		90
238,458			7,574,780		91
612,914		14,262	12,652,489		92
			13,938,120		93
2,972,236		33,080	53,788,304		94
425,525			5,577,125		95
7,476,805		35,691	339,201,272		96
					97
					98
7,476,805		35,691	339,201,272		99
48,400,685	-3,673,688		5,248,212,331		100
					101
					102
					103
48,400,685	-3,673,688		5,248,212,331		104

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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ELECTRIC PLANT LEASED TO OTHERS (Account 104)

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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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			109,961
4	Transmission Stations			423,089
5	Transmission Lines			195,489
6	Distribution Stations			1,077,217
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			69,941
25	Homedale Substation	2/29/08		217,797
26	Beacon Light Substation	12/30/02		555,940
27				
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45				
46				
47	Total			7,090,431

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	ROLLUP RELIC COST BROWNLEE	79,830,017
2	ROLLUP RELIC COST HELLS CANYON	54,409,576
3	GATEWAY WEST 500KV LINE	26,705,505
4	BRIDGER 2011C038 JB3 SCR SYS D	26,503,011
5	ROLLUP RELIC COST OXBOW	25,260,594
6	BOARDMAN - HEMINGWAY 500 KV LI	21,460,986
7	HELLS CANYON RELICENSING OUTSI	20,296,218
8	BRIDGER 2011C039 JB4 SCR SYS D	17,320,740
9	CIAC LIABILITY RECLASS	10,570,351
10	BROWNLEE TURBINE REFURBISHMENT	8,913,910
11	B2H PERMITTING 11/1/2011 & FOR	7,534,197
12	BRIDGER UNDISTRIBUTED WORK ORD	5,358,000
13	VALMY 98281993 V2 COOLING TOWE	4,984,852
14	VALMY UNDISTRIBUTED WORK ORDER	3,964,000
15	VALMY 98306281V2 SCRUBBER INLE	3,489,100
16	MPSN REPLACE C232&C233 SERIES	2,798,630
17	VALMY 98306280 V2 SCRUBBER SPR	2,777,076
18	LEGAL DEPT. LABOR FOR RELICENS	2,711,029
19	LOWER SALMON RUNNER REPLACEMEN	2,369,744
20	REL-HCC OREGON REAUTHORIZATION	2,327,924
21	B2H TLINE CONSTRUCTION COSTS	2,286,270
22	HCC WATERSHED ENHANCEMENT PROG	2,213,993
23	CORPORATE AIRPLANE ENGINE REPL	2,102,511
24	CHQB100177 - SPARE XFRMR LANGL	1,963,324
25	BRIDGER 2012C075 U1 MERCURY CO	1,821,189
26	BRIDGER 2012C076 U2 MERCURY CO	1,813,914
27	BRIDGER 2012C078 U4 MERCURY CO	1,805,544
28	BRIDGER 2012C077 U3 MERCURY CO	1,800,943
29	HCPR110116 REPL T233 GSU	1,624,495
30	PAYROLL & IBNR ACCRUAL	1,545,259
31	BRIDGER 2014C037 U3 REPLACE FI	1,476,314
32	HBND-041:ALT LINE ROUTE TO GAR	1,316,817
33	WQ HCC401 APPLICATION, REVISIO	1,279,798
34	WDRI-KCHM NEW 138KV	1,273,198
35	TNDY ADD 69 KV BREAKERS EXPAND	1,213,293
36	RELICENSING: BAKER COUNTY SETT	1,200,163
37	REC - BAKER COUNTY SETTLEMENT	1,120,300
38	WQ HCC401 CERTIFICATION OPS AN	1,083,319
39	314 DESIGN TEAMS - CAPITAL - C	1,068,315
40	FALL CHINOOK PROGRAM - REDD SU	1,067,075
41	OTHER MINOR PROJECTS UNDER $1,000,000	41,268,015
42		
43	TOTAL	401,929,509

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

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

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	1,919,582,910	1,919,582,910		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	125,245,540	125,245,540		
4	(403.1) Depreciation Expense for Asset Retirement Costs	495,029	495,029		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	3,723,850	3,723,850		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9	Fuel Stock	102,213	102,213		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	129,566,632	129,566,632		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	43,281,494	43,281,494		
13	Cost of Removal	10,451,825	10,451,825		
14	Salvage (Credit)	1,921,106	1,921,106		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	51,812,213	51,812,213		
16	Other Debit or Cr. Items (Describe, details in footnote):				
17	CIAC, Reserve Adj and ARO activity.	571,089	571,089		
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	1,997,908,418	1,997,908,418		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	541,682,229	541,682,229		
21	Nuclear Production				
22	Hydraulic Production-Conventional	390,670,339	390,670,339		
23	Hydraulic Production-Pumped Storage				
24	Other Production	72,501,209	72,501,209		
25	Transmission	312,623,040	312,623,040		
26	Distribution	567,894,311	567,894,311		
27	Regional Transmission and Market Operation				
28	General	112,537,290	112,537,290		
29	TOTAL (Enter Total of lines 20 thru 28)	1,997,908,418	1,997,908,418		

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INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

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

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	Idaho Energy Resources Company			
2	Common Stock	02/01/74		500
3	Capital contributions			2,462,594
4	Equity in earnings			88,921,479
5				
6	Subtotal Idaho Energy Resources Company			91,384,573
7				
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42	Total Cost of Account 123.1 $ 2,463,094		TOTAL	91,384,573

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INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues 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
7,092,887	15,000,000	81,014,366		4
				5
7,092,887	15,000,000	83,477,460		6
				7
				8
				9
				10
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7,092,887	15,000,000	83,477,460		42

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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)	41,546,323	55,170,482	Electric
2	Fuel Stock Expenses Undistributed (Account 152)		599	Electric
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)	16,506,169	17,010,420	
8	Transmission Plant (Estimated)	10,947,716	11,212,105	
9	Distribution Plant (Estimated)	20,538,847	20,564,459	
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	1,274,973	1,518,495	
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	49,267,705	50,305,479	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)	4,375,589	5,098,760	Electric
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	95,189,617	110,575,320	

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Allowances (Accounts 158.1 and 158.2)

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

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2015 No. (d)	2015 Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Allowances (Accounts 158.1 and 158.2) (Continued)

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

2016		2017		Future Years		Totals		Line No.
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	
								1
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

Allowances (Accounts 158.1 and 158.2)

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

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2015 No. (d)	2015 Amt. (e)
1	Balance-Beginning of Year				
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509				
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year				
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

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

2016		2017		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
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Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
1						
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19						
20	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
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48						
49	TOTAL					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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	BLACK CANYON SISR	4,210	186623	(5,370)	186623
3	BPAP NETWORK SIS 78318516	2,776	186623		186623
4	BPAP NETWORK SIS 78862937	3,627	186623	3,447	186623
5	BPAP TRANS SIS 80289606	1,831	186623	(10,000)	186623
6	PAC PTP SIS 80381517		186623	(10,000)	186623
7					
8					
9					
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19					
20					
21	**Generation Studies**				
22	ALAMEDA SOLAR CENTER - GI 416		186623	(738)	186623
23	AMERICAN FALLS SOLAR # 431	10,601	186623	(20,127)	186623
24	AMERICAN FALLS SOLAR II # 433	6,725	186623	(13,508)	186623
25	BENSON CREEK WINDFARM GI 401	3,781	186623		186623
26	BLACK CREEK SOLAR #434	4,915	186623	(4,914)	186623
27	BOISE CITY SOLAR #432	13,775	186623	(50,000)	186623
28	BURNT RIVER #2 PROJECT 251		186623	96,144	186623
29	BURNT RIVER PROJECT 209		186623	91,424	186623
30	CLARK 2 SOLAR-20MW #438	85	186623	(1,000)	186623
31	CLARK 4 SOLAR-20MW #440	85	186623	(1,000)	186623
32	CLARK SOLAR 1 #437 7MW	857	186623	(10,000)	186623
33	CLARK SOLAR 3 #439 30MW	170	186623	(10,000)	186623
34	EIGHTMILE HYDRO GI 406	(159)	186623		186623
35	GRANDVIEW PV SOLAR FIVE GI 411	17,838	186623	(27,479)	186623
36	GRANDVIEW PV SOLAR FIVEA GI 418		186623	(1,300)	186623
37	GROVE SOLAR CENTER - GI 414	5,981	186623	(31,187)	186623
38	HEAD OF THE U HYDRO GI 409	1,605	186623	12,502	186623
39	HORSE CREEK SOLAR CENTER - GI 417		186623	(1,171)	186623
40	HYLINE SOLAR CENTER - GI 419	25,129	186623	(39,247)	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					
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20					
21	**Generation Studies**				
22	LITTLE WOOD RIVER RANCH II GI 410	1,741	186623	(5,136)	186623
23	MAGPIE WIND PROJECT 235		186623	104,869	186623
24	MOUTAIN HOME SOLAR-20MW #435		186623	(1,000)	186623
25	MT. HOME SOLAR #444		186623	(1,000)	186623
26	MURPHY FLAT POWER NORTH #426	8,486	186623	(13,423)	186623
27	MURPHY FLAT POWER SOUTH #427	3,540	186623	(1,000)	186623
28	MURPHY FLAT WIND FARM	244	186623	35,176	186623
29	OPEN RANGE SOLAR CENTER - GI 413	21,796	186623	(31,965)	186623
30	ORCHARD RANCH SOLAR-20MW #441		186623	(1,000)	186623
31	POCATELLO SOLAR-20MW #436		186623	(1,000)	186623
32	RAILROAD SOLAR CENTER - GI 423	12,652	186623	(37,842)	186623
33	RAILROAD SOLAR CENTER - GI 424	16,818	186623	(35,858)	186623
34	SAGEBRUSH SOLAR CENTER - GI 415		186623	153	186623
35	SALMON RIVER CANAL 550KW	1,534	186623	(1,000)	186623
36	SIMCO SOLAR #442		186623	(1,000)	186623
37	SIMCOE SOLAR CENTER #428	5,489	186623	(13,426)	186623
38	TILLI SOLAR #443		186623	(1,000)	186623
39	TURNER SOLAR CENTER - GI 420	2,707	186623	(1,707)	186623
40	VALE AIR SOLAR CENTER - GI 412	20,012	186623	(39,111)	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					
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7					
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9					
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14					
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16					
17					
18					
19					
20					
21	**Generation Studies**				
22	WRIGHT PLACE SOLAR #445		186623	(1,000)	186623
23					
24					
25					
26					
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Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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	Asset Retirement Obligations (182341)	16,765,815	416,799	230	148,979	17,033,635
2	IPUC Order# 29414-OPUC Order# 04-585					
3						
4	ASC 815 Mark to Market - ST (182330)	1,628,450	9,198,642	244	6,866,388	3,960,704
5						
6	FAS 109 Unfunded (182322)	710,482,403	91,705,942	282		802,188,345
7	Accum Deferred Income Noncurrent					
8						
9	PCA Deferral Idaho - IPUC Order #33049	63,093,814	55,993,923	Various	73,675,167	45,412,570
10	(Amort period 06/15 thru 05/16) (182323)					
11						
12	PCA Prior Year Deferral Idaho - IPUC Order #33049	30,418,393	58,426,586	various	76,309,131	12,535,848
13	(Amort period 06/14 thru 05/15) (182324)					
14						
15	Fixed Cost Adjuustment (FCA) (182302)	15,431,297	17,444,594	440/421	16,063,980	16,811,911
16	IPUC Order #33047 (Amort period 06/15 thru 05/1					
17						
18	Prior Year FCA IPUC Order #33047 (182309)	4,094,478	14,912,443	440/442	12,081,243	6,925,678
19	(Amort period 6/14 thru 5/15)					
20						
21	AOCI Impact of Unfunded Post Retirement Liability	(4,646,030)	5,732,807	228	182,989	903,788
22	IPUC Order #30256 (182306)					
23						
24	Oregon Pension Expense Capitalized (182339)	2,524,479	342,884	401/4073	116,997	2,750,366
25	OPUC Order #10-064 (Amort period thru 2052)					
26						
27	Deferred Pension Expense Net of Contributions	27,062,657	22,613,747	421/228	29,598,897	20,077,507
28	IPUC Order #30333 (182321)					
29						
30	AOCI Impact of Unfunded Pension Liability	121,228,583	146,725,287	228	4,309,107	263,644,763
31	IPUC Order #30256 (182320)					
32						
33	PCA Unbilled Forecast IPUC Order #53049 (182325)	(6,092,288)	38,352,606	401	33,316,131	-1,055,813
34						
35	PCAM Oregon 2008 (182346)	7,538,300	181,051	557/421	2,184,844	5,534,507
36	OPUC Order #08-238 & UE277 (Amort 1/14 - 7/17)					
37						
38	PCAM Interest Reserve 2008 (182329)	(793,327)	224,898	421		-568,429
39	OPUC Order #08-238 & UE 277 (Amort 1/14 - 7/17)					
40						
41	Excess Power Cost Deferral 2007 (182358)	26,915	69	401/421	26,984	
42	IPUC Order #09-189 (amort period 1/11 - 1/14)					
43						

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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	Idaho Boardman Decomissioning #32549 (182493)	749,740	6,380,447	various	5,912,680	1,217,507
2						
3						
4	2009 Reorg IPUC Order #30914 (182318)	230,655		401	230,655	
5	(Amort period 01/10 thru 12/14)					
6						
7	OATT Revenue Deferred Reserve (182336)	974,888		400	688,156	286,732
8	IPUC Order #30940 (amort period 06/12 thru 5/15)					
9						
10	Idaho Pension Cash (182327)	45,520,420	29,143,134	401/421	33,846,846	40,816,708
11	IPUC Order #32248					
12	(Amort period beginning 06/11 thru unknown)					
13						
14	2008 PCAM Unbilled Amort (182356)	(136,099)	1,793,467	557/421	1,815,670	-158,302
15	(Amort period 1/14 thru 7/17)					
16						
17	Lidar Surveys IPUC Order #32426 (182361)	348,837		402	43,604	305,233
18	(Amort period 01/12 thru 12/21)					
19						
20	Bennett Mtn Maintenance IPUC Order #32426	149,773		402	74,886	74,887
21	(Amort period 01/12 thru 12/15) (182379)					
22						
23	PCA Unbilled Amortization (182316)	(2,576,701)	48,408,091	400/401	48,212,040	-2,380,650
24	(Amort period 06/14 thru 05/15)					
25						
26	Idaho Boardman ARO Order #32549 (182393)	1,204,047		403/411	942,707	261,340
27	(Amort period thru 2020)					
28						
29	Langley Revenue Accrual Order #12-226 (182398)	872,084	69,873			941,957
30						
31	Minor items (32)	273,536	393,241	various	363,845	302,932
32						
33						
34						
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42						
43						
44	**TOTAL :**	1,036,375,119	548,460,531		347,011,926	1,237,823,724

Schedule Page: 232 Line No.: 9 Column: d

Contra accounts include 557, 421, 254, 440.

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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	Prepaid ROW (186160)	659,834	12,898	401	246,788	425,944
2	Rents/Easements Long Term					
3						
4	Long-Term Portfolio (186255)	54,483	5,050,228	165	3,313,563	1,791,148
5						
6	Advance Prepaid (186709)	1,306,535		151	64,925	1,241,610
7	Coal Royalties					
8						
9	Security plan (186720)	18,115,431	8,160,417	426	6,216,769	20,059,079
10	Net Insurance Asset					
11						
12	American Falls Bond Ref(186722)	162,500		401	14,552	147,948
13	(Amort 04/00 - 02/25)					
14						
15	Prepaid Credit Facility(186025)	907,071		431	237,675	669,396
16	(amort period 10/12 thru 10/17)					
17						
18	Company Owned (186726)	3,921,641	1,063,448	426	1,150,865	3,834,224
19	Life Insurance					
20						
21	American Falls Water Rights	11,548,930		401	1,042,009	10,506,921
22	(amort 01/06 - 02/25) (186727)					
23						
24	Milner Bond Guarantee (186734)	4,254,545		253	1,063,636	3,190,909
25	(Amort 02/07 - 2/17)					
26						
27	American Falls - Bond refinance	535,991		401	48,000	487,991
28	(Amort through 02/25)(186770)					
29						
30	Shelf Registration (186732)	160,469	22	186	22	160,469
31						
32	Prepaid Exp (186052)	837,710	1,802,964	various	981,269	1,659,405
33	Contract I.T. Long Term					
34						
35	Long Term (186121)	1,186,330	6,639	228/401	62,220	1,130,749
36	Workers Compensation					
37						
38	Power Plant- Bridger (186780)		680,403	401	425,610	254,793
39						
40	Transmission & Generation	79,544	3,362,877	various	3,442,421	
41	Studies (186623)					
42						
43	Prepaid Coal LT (186797)	1,458,328		151/401	1,458,328	
44						
45	Minor Items (2)	19,424	48,977	Various	64,274	4,127
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	45,208,766				45,564,713

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	04/15/2015	End of 2014/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			
4			
5	Other Electric (See footnote)	118,958,964	97,597,101
6			
7	Other (See footnote)	106,991,643	169,747,033
8	TOTAL Electric (Enter Total of lines 2 thru 7)	225,950,607	267,344,134
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	20,824,214	21,759,450
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	246,774,821	289,103,584

Notes

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

	Beginning Balance	Ending Balance
Federal NOL-Operating	28,544,014	0
Prov for Rate Refund-HC Relicensing (AFUDC)	23,062,458	28,529,481
Regulatory Asset-Non Current	23,538,502	18,067,486
Deferred Idaho ITC	15,346,759	17,378,549
VEBA-Post Retirement Benefits	9,962,466	10,617,384
Incentive Deferral-Profit Sharing-Not in Rates	0	5,085,262
Stock Based Compensation-FAS123R	3,532,282	3,782,196
Revenue Sharing	2,972,019	3,127,266
Pension Expense-Oregon	2,204,483	2,488,771
Rate Case Disallowance	2,389,579	2,273,741
Regulatory Liability-Current	1,826,860	1,918,442
Construction Advances	2,059,244	1,016,324
Valmy Union Pacific Contract	1,083,462	919,072
Asset Retirement Obligation (ARO)	425,053	865,690
M & E Reserve	0	592,049
Postretirement Benefits-SFAS112	579,781	568,869
Bridger Revenue Deferral	191,185	316,603
Executive Deferred Compensation	450,715	54,988
Deferred GBC Federal	31,500	31,500
CSPP Co-Generator Overpayment	470,282	0
Oregon NOL-Operating	247,299	0
Provision for Rate Refunds	155,600	0
Montana NOL-Operating	101,480	0
Boardman Decommission	(298,653)	0
Non-VEBA Pension and Benefits	82,596	(36,572)
Total Other Electric	118,958,964	97,597,101

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

Pension-FAS 158	47,394,315	103,071,920
Regulatory Asset-FASB 109	50,788,061	50,814,726
Minimum Pension Liability	10,625,633	15,507,051
Postretirement Plan-FAS 158	(1,816,365)	353,336
Total Other	106,991,643	169,747,033

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

Senior Management Security Plan	19,664,453	21,402,608
Micron CIAC-Depr Timing Diff	574,719	336,836
Federal NOL-Non Operating	534,662	0
Meridian Gold CIAC-Depr Timing Diff	42,118	20,006
Oregon NOL-Non Operating	6,409	0
Montana NOL-Non Operating	1,854	0
Total Non Electric	20,824,214	21,759,450

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	04/15/2015	End of 2014/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 all of which is held by	50,000,000	2.50	
3	IdaCorp, Inc. and not traded			
4	Total Common Stock	50,000,000	2.50	
5				
6	Account 204 - None			
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
39,150,812	97,877,030					2
						3
39,150,812	97,877,030					4
						5
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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	
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39		
40	TOTAL	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

CAPITAL STOCK EXPENSE (Account 214)

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

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

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	4.00% Series due 2043	75,000,000	742,017
19			193,836 D
20			
21	6.00% Series due 2032	100,000,000	1,191,216
22			543,244 D
23			
24	5.875% Series due 2034	55,000,000	-585,759
25			746,961 D
26			
27	5.50% Series due 2034	50,000,000	524,419
28			383,322 D
29			
30	4.85% Series Due 2040	100,000,000	1,284,871
31			169,984 D
32			
33	TOTAL	1,627,045,000	26,907,384

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	04/15/2015	End of 2014/Q4

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	6.30% Series due 2037	140,000,000	1,495,799
2			278,367 D
3			
4	6.25% Series due 2037	100,000,000	1,141,489
5			267,677 D
6			
7	Port of Morrow Variable due 2027	4,360,000	188,545
8	Humboldt Variable due 2024	49,800,000	1,697,856
9	Sweetwater Variable due 2026	116,300,000	3,026,122
10			
11	2.50% Series due 2023	75,000,000	648,267
12			371,854 D
13			
14	6.025 % Series Due 2018	120,000,000	1,630,120
15			
16	4.30% Series Due 2042	75,000,000	802,240
17			49,417 D
18	2.95% Series Due 2022	75,000,000	708,490
19			127,607 D
20	Subtotal Account 221	1,595,460,000	26,907,384
21			
22	Account 222 - Reaquired Bonds		
23			
24	Account 223: Advances for Associated Companies		
25			
26	Account 224:		
27	Bond Guarantee - American Falls	19,885,000	
28	Note Guarantee - Milner Dam	11,700,000	
29	Subtotal Account 224	31,585,000	
30			
31			
32			
33	TOTAL	1,627,045,000	26,907,384

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	04/15/2015	End of 2014/Q4

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
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
4/8/2013	4/1/2043	4/8/2013	4/1/2043	75,000,000	3,000,000	18
						19
						20
11/15/02	11/15/32	11/15/02	11/15/32	100,000,000	6,000,000	21
						22
						23
08/16/04	08/16/34	08/16/04	08/16/34	55,000,000	3,231,250	24
						25
						26
03/26/04	03/15/34	03/26/04	03/15/34	50,000,000	2,750,000	27
						28
						29
2/15/10	8/15/40	2/15/10	8/15/40	100,000,000	4,850,000	30
						31
						32
				1,618,535,909	80,561,920	33

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
6/22/07	6/15/2037	6/22/07	6/15/37	140,000,000	8,820,000	1
						2
						3
10/18/07	10/15/2037	10/18/07	10/15/37	100,000,000	6,250,000	4
						5
						6
05/17/00	02/01/27	05/17/00	02/01/27	4,360,000	17,720	7
10/22/03	12/01/24	11/01/03	12/01/24	49,800,000	2,564,700	8
10/3/06	7/15/26	10/3/06	7/15/26	116,300,000	6,105,750	9
						10
4/8/2013	4/1/2023	4/8/2013	4/1/2023	75,000,000	1,875,000	11
						12
						13
7/10/08	7/15/18	7/10/08	7/15/08	120,000,000	7,230,000	14
						15
4/13/12	4/1/42	4/13/12	4/1/42	75,000,000	3,225,000	16
						17
4/13/12	4/1/22	4/13/12	4/1/22	75,000,000	2,212,500	18
						19
				1,595,460,000	80,561,920	20
						21
						22
						23
						24
						25
						26
04/26/00	2/1/25			19,885,000		27
02/10/92				3,190,909		28
				23,075,909		29
						30
						31
						32
				1,618,535,909	80,561,920	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	04/15/2015	End of 2014/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)	189,386,993
2		
3		
4	Taxable Income Not Reported on Books	
5		-98,931,827
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		50,782,788
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		19,918,608
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		114,202,966
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	7,116,380
28	Show Computation of Tax:	
29	Tenative Federal Tax @ 35%	2,490,733
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44		

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

4000-FEDERAL NOL	$	(113,211,345)
4003-CONSTRUCTION ADVANCES		(2,979,771)
4005-AVOIDED COST		6,508,216
4010-EMISSION ALLOWANCES (ACCT 283)		13,495
4013-CIAC - TAXABLE - ACCT 107		8,850,300
4021-ENGINEERING FEES - TAXABLE - ACCT 107		528,786
4024-RENEWABLE ENERGY CERTIFICATES (REC) SALES		2,023,523
4506-MERIDIAN GOLD CIAC - DEPR TIMING DIFF - NON-OP		(56,560)
4507-MICRON CIAC - DEPR TIMING DIFF - NON-OP		(608,471)
Total	**$**	**(98,931,827)**

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

Total Federal and State taxes deducted on books	$	15,784,451
5001-BAD DEBT EXPENSE		(398,034)
5010-POSTEMPLOYMENT BENEFITS-SFAS112		(27,913)
5014-VACATION ACCRUAL TAX ADJ - ACCT 242		586,964
5017-INJURIES & DAMAGES		379,858
5019-DEFERRED DIRECTORS FEES		(343,330)
5022-263A CAPITALIZED OVERHEADS		(25,000,000)
5023-PENSION EXPENSE (ACCT 283)		3,846,847
5024-NON-DEDUCTIBLE MEALS		500,000
5025-MILNER FALLING WATER		(48,550)
5028-OREGON OPERATING PROPERTY TAX ADJ		(9,810)
5033-NON-VEBA PENSION & BENEFITS		(304,817)
5035-PCA EXPENSE DEFERRAL		30,331,264
5043-AMERICAN FALLS - FALLING WATER CONTRACT		219,181
5046-EXECUTIVE DEFERRED COMP - ST		(984,570)
5047-EXECUTIVE DEFERRED COMP - LT		(27,649)
5048-BONUS DEFERRAL-OPERATING (DT 283) (Old Event)		(13,834)
5070-INCENTIVE DEFERRAL-CRI & RELIABILITY-INCLUDED IN RATES		8,189,137
5071-INCENTIVE DEFERRAL-PROFIT SHARING-NOT IN RATES (DT 190)		13,007,448
5052-AMORTIZATION OF ACCOUNT 181		272,059
5053-STOCK BASED COMPENSATION - FAS 123R		659,039
5055-OPUC GRID WEST LOANS		14,191
5057-INTERVENER FUNDING ORDERS		(98,495)
5058-FIXED COST ADJUSTMENT		(4,211,813)
5060-OREGON - PCAM		1,776,896
5061-PENSION EXPENSE - OREGON		727,172
5062-2011 LIDAR SURVEYS DEFERRAL		43,605
5063-BENNETT MTN MAINT DEFERRAL		74,886
5064-BRIDGER REVENUE DEFERRAL		320,803
5065-VALMY UNION PACIFIC CONTRACT		(420,488)
5066-BOARDMAN DECOMMISSION (DT 190)		763,915
5066-BOARDMAN DECOMMISSION (DT 283)		(1,238,525)
5067-ASSET RETIREMENT OBLIGATION (ARO)		804,745
5068-CSPP CO-GENERATOR OVERPAYMENT		(1,202,920)
5069-M & E RESERVE		1,514,386
5501-SMSP - INSURANCE COSTS		(177,316)
5503-EDC - UNREALIZED GAIN/LOSS FROM RABBI TRUST		(19,873)
5504-NON-DEDUCTIBLE POLITICAL EXPENSES		1,171,441

5505-SMSP - NET		4,445,979
5510-FINES & PENALTIES - OPERATING.		36,000
5516-NON-DEDUCTIBLE POLITICAL EXP - O&M ACCTS		100,000
5517-SMSP - UNREALIZED GAIN/LOSS FOR TAX		49,886
5531-RATE CASE DISALLOWANCES		(296,299)
5532-DELIVERY ACCRUALS		(13,129)
Total	**$**	**50,782,788**

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7009-PROVISION FOR RATE REFUNDS	$	398,006
7010-PROV FOR RATE REFUND - HC RELICENSING (AFUDC)		(13,983,946)
7011-OATT REVENUE DEFICIENCY		(688,156)
7012-REVENUE SHARING		(397,102)
7013-LANGLEY REVENUE ACCRUAL		48,838
7501-REVERSE EQUITY EARNINGS OF SUBSIDIARIES		7,092,887
7502-ALLOWANCE FOR OFUDC		17,930,898
7503-ALLOWANCE FOR BFUDC		8,464,109
7509-SMSP - INSURANCE PROCEEDS		1,053,074
Total	**$**	**19,918,608**

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8001-VEBA - POST RETIREMENT BENEFITS	$	(1,731,048)
8009-DEPR TIMING DIFF - OPERATING - FEDERAL		12,993,378
8020-CONSERVATION EXPENSES		973,123
8025-MANUFACTURING DEDUCTION		5,296,634
8027-NEVADA OPERATING PROPERTY TAX ADJ		142,023
8034-REMOVAL COSTS		10,445,838
8038-OREGON EXCESS POWER COSTS		(47,212)
8041-AMERICAN FALLS REFINANCE - OLD COSTS		(47,999)
8042-GAIN/LOSS ON REACQUIRED DEBT		(1,060,585)
8057-REORGANIZATION COSTS		(230,656)
8059-SOFTWARE - LABOR COSTS DEDUCTED - ACCT 107		500,000
8072-RELICENSING - LABOR COSTS DEDUCTED - ACCT 107		2,800,000
8073-REPAIRS DEDUCTION		75,000,000
8077-PREPAID INSURANCE & OTHER EXPENSES		(605,997)
8501-COLI - INSURANCE COSTS		112,012
8504-OREGON NON-OP PROPERTY TAX ADJUSTMENT		55
8703-IPCO - 162 (M) $1m THRESHOLD		(207,282)
8901-REGULATORY ASSET - CURRENT		(13,994,159)
8901-REGULATORY ASSET - NON CURRENT		13,994,159
8902-REGULATORY LIABILITY - CURRENT		(234,256)
8902-REGULATORY LIABILITY - NON CURRENT		234,256
STATE INCOME TAX DEDUCTED ON FEDERAL RETURN		9,870,682
Total	**$**	**114,202,966**

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

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

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust- ments (f)
1	Federal:					
2	Income	4,917,038		-10,331,231	12,446,979	
3	Social Security - (FOAB)	-13		14,043,578	14,044,743	
4	Unemployment			91,850	91,850	
5	Subtotal Federal	4,917,025		3,804,197	26,583,572	
6						
7	State of Idaho:					
8	Property	8,961,328		20,820,653	20,753,612	
9	Non-Operating	10,639		23,015	22,146	
10	Income	-139,933		6,921,987	9,695,941	
11	KWH	98,314		1,404,355	1,416,517	
12	Unemployment			651,894	651,894	
13	Regulatory Commission			2,688,423	2,688,423	
14	Business License - Sho Ban			150	150	
15	Subtotal Idaho	8,930,348		32,510,477	35,228,683	
16						
17	State of Oregon					
18	Property		1,425,833	2,862,775	2,872,585	
19	Non-Operating Property		863	1,782	1,837	
20	Income	-6,462		-110,880	54,224	
21	Regulatory Commission			186,899	186,899	
22	Unemployment			51,486	51,486	
23	Franchise	213,724		800,080	807,855	
24	Subtotal Oregon	207,262	1,426,696	3,792,142	3,974,886	
25						
26	State of Montana:					
27	Property	144,976		321,531	305,096	
28	Subtotal Montana	144,976		321,531	305,096	
29						
30	State of Nevada:					
31	Property		360,323	1,173,729	1,315,753	
32	Subtotal Nevada		360,323	1,173,729	1,315,753	
33						
34	State of Wyoming					
35	Corporate License			4,744	4,744	
36	Property	775,189		1,604,927	1,577,652	
37	Subtotal Wyoming	775,189		1,609,671	1,582,396	
38	Other States Income	128,086		-140,147	5,336	
39	Payroll Tax Credit			-14,838,808		
40	Canada GST tax	1,524			5,060	-37,631
41	TOTAL	15,104,410	1,787,019	28,232,792	69,000,782	-37,631

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
-17,861,172		-7,413,733			-2,917,498	2
-1,179		14,043,578				3
		91,850				4
-17,862,351		6,721,695			-2,917,498	5
						6
						7
9,028,370		20,819,856			797	8
11,508					23,015	9
-2,913,887		7,129,371			-207,384	10
86,152		1,404,355				11
		651,894				12
		2,688,423				13
		150				14
6,212,143		32,694,049			-183,572	15
						16
						17
	1,435,643	2,743,535			119,240	18
	918				1,782	19
-171,566		-87,450			-23,430	20
		186,899				21
		51,486				22
205,949		800,080				23
34,383	1,436,561	3,694,550			97,592	24
						25
						26
161,411		321,531				27
161,411		321,531				28
						29
						30
	502,346	1,173,729				31
	502,346	1,173,729				32
						33
						34
		4,744				35
802,464		1,604,927				36
802,464		1,609,671				37
-17,398		-133,337			-6,810	38
		-14,838,808				39
34,095						40
-10,635,253	1,938,907	31,243,080			-3,010,288	41

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

```
Account 409.2       $  (914,126)
Account 234.020      (2,003,372)
                    ------------
Total               $(2,917,498)
                    ============
```

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

```
Account 107       $   797
```

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

```
Account 408.2       $  23,015
```

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

```
Account 409.2       $  (23,447)
Account 234.020       (183,937)
                    -----------
Total               $ (207,384)
                    ===========
```

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

```
Account 107       $ 119,240
```

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

```
Account 408.2       $  1,782
```

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

```
Account 409.2       $ (14,076)
Account 234.020        (9,353)
                    ----------
Total               $ (23,430)
                    ==========
```

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

```
Account 409.2       $ (3,692)
Account 234.020       (3,118)
                    ---------
Total               $ (6,810)
                    =========
```

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

This amount is an offset to lines 3, 4, 11 & 22. Each month employer paid taxes flow into various 408.1 accounts. In that same month these amounts are offset with a different 408.1 account. These payroll taxes are then allocated back to the balance sheet and O & M accounts based on current month labor charges.

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

Canada GST accrual is an adjustment because the offset account is not a 600 expense account.

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	04/15/2015	End of 2014/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		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%	541,998				53,324	-54,475
4	7%						
5	10%	21,047,565				1,402,464	54,475
6		1,187,853				26,029	
7		56,343,874	411.4	3,044,087	411.4	1,520,729	
8	TOTAL	79,121,290		3,044,087		3,002,546	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Line 6 Col A 11%						
11							
12	State of Idaho	56,343,874	411.4	3,044,087	411.4	1,520,729	
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
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42							
43							
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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	04/15/2015	End of 2014/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
434,199	10.16		3
			4
19,699,576	15.01		5
1,161,824	45.64		6
57,867,232	37.05		7
79,162,831			8
			9
			10
			11
57,867,232			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

Schedule Page: 266 Line No.: 3 Column: g

The adjusting entry is to tie the ending balance to the record detail and work papers.

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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)	900,249	107/401	1,111,121	210,872	
2						
3	Point to Point Trans Study(253201)	899,702	2472	86,000	474,248	1,287,950
4						
5	FTV (253202)	3,266,666	400	400,000		2,866,666
6	(Amort Period Mar 1998-Feb 2023)					
7						
8	Sho Ban Trans ROW (253480)	217,500	107	15,000		202,500
9	(Amort Period Jan 2005-Dec 2027)					
10						
11	Milner Falling Water (253953)	715,735	186/401	1,165,699	1,117,149	667,185
12	Amort Period (Feb 1992 - Feb 2017)					
13						
14	Postretirement Benefits (253960)	1,483,006	401	27,913		1,455,093
15						
16	Directors Deferred Compensation	4,226,431	131	932,967	589,636	3,883,100
17	(253980-253999)					
18						
19	Operations Accrual (253550)	676,000	232/401	74,435	669,823	1,271,388
20	(amort period 1 year for dues)					
21						
22	Minor Items (1) 253042	1,432	various	44,478	44,806	1,760
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	12,386,721		3,857,613	3,106,534	11,635,642

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

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

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

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
							15
							16
							17
							18
							19
							20
							21

NOTES (Continued)

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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	436,837,016	30,575,458	16,294,782
3	Gas			
4	Other			
5	TOTAL (Enter Total of lines 2 thru 4)	436,837,016	30,575,458	16,294,782
6	Non-Operating Property			
7	Other - Regulatory Asset	706,253,450		
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)	1,143,090,466	30,575,458	16,294,782
10	Classification of TOTAL			
11	Federal Income Tax	980,163,502	30,306,822	16,294,782
12	State Income Tax	162,926,964	268,636	
13	Local Income Tax			

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
						451,117,692	2
							3
							4
						451,117,692	5
							6
		182	446,723	182	91,705,942	797,512,669	7
							8
			446,723		91,705,942	1,248,630,361	9
							10
			374,733		77,748,031	1,071,548,840	11
			71,990		13,957,911	177,081,521	12
							13

NOTES (Continued)

Schedule Page: 274 Line No.: 5 Column: b

Account (a)	2014 Beginning Balance b	Changes during Year DR to 410.1 c	CR to 411.1 d	DR to 410.2 e	CR to 411.2 f	Adj Dr Acct. Cr g	Amt h	Adj Cr Acct. Dr. i	Amt j	2014 End Bal k
Depr Timing Diff-Oper	424,062,833	28,367,950	12,652,571							439,778,212
Intang-labor costs- Acct 107	14,385,202	2,997,709								17,382,911
CIAC-Taxable-Acct 107	(3,060,909)	430,646	3,380,470							(6,010,733)
Valmy Capitalized Items	198,266		76,500							121,766
Software - labor costs	1,567,943	(1,220,847)								347,096
Eng Fees in Acct 107	(316,318)		185,241							(501,560)
TOTAL	436,837,016	30,575,458	16,294,782	0	0		0		0	451,117,692

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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	91,672,316	51,837,119	69,353,539
4				
5				
6				
7				
8	Other -- See Note	45,577,950		
9	TOTAL Electric (Total of lines 3 thru 8)	137,250,266	51,837,119	69,353,539
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other -- See Note	838,607		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	138,088,873	51,837,119	69,353,539
20	Classification of TOTAL			
21	Federal Income Tax	115,836,413	43,483,779	58,177,498
22	State Income Tax	22,252,460	8,353,340	11,176,041
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						
		Debits		Credits				
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
						74,155,896	3
							4
							5
							6
							7
					57,847,307	103,425,257	8
					57,847,307	177,581,153	9
							10
							11
							12
							13
							14
							15
							16
							17
80,909	68,392					851,124	18
80,909	68,392				57,847,307	178,432,277	19
							20
67,871	57,371				48,525,449	149,678,643	21
13,038	11,021				9,321,858	28,753,634	22
							23

NOTES (Continued)

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

	2014	Changes during Year				Adj Dr		Adj Cr		2014
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	End Bal k
Pension Expense	20,232,517	20,309,544	21,607,803							18,934,259
PCA Expense	33,169,456	6,656,883	18,514,891							21,311,448
Conservation Exp	1,409,026	3,426,730	3,046,288							1,789,468
Fixed Cost Adj	7,633,602	2,203,129	556,520							9,280,211
Reg Asset-Current	23,538,502	15,615,540	21,086,556							18,067,486
Oregon PCAM	2,636,947	0	694,677							1,942,270
Reg Liab-Non Current	1,826,860	2,647,701	2,556,119							1,918,442
Boardman Decommission	0	537,210	53,009							484,201
Oregon Excess Power Costs	(43,430)	6,432	24,889							(61,888)
OATT Revenue Deficiency	381,132		269,035							112,098
Renewable Energy Cert-sales	217,848	345,165	791,096							(228,084)
Langley Revenue Accr	331,688	19,093								350,781
Reorganization Costs	90,175	0	90,175							(0)
2011 LIDAR Surveys Def	136,378	0	17,047							119,331
Bennett Mtn Maint Def	58,554		29,277							29,277
Intervenor Funding Orders	82,837	38,507								121,344
OPUC Grid West Loans	6,472	0	5,548							925
Emission Allowances	(751)	9,749	5,276							3,722
Bonus Deferral	(10,970)	10,970								0
Delivery Accruals	(24,528)	10,465	5,332							(19,395)
TOTAL	91,672,316	51,837,119	69,353,539	0	0		0		0	74,155,896

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

	2014	Changes during Year				Adj Dr		Adj Cr		2014
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	End Bal k
Pension-FAS 158	47,394,315							190	55,677,606	103,071,921
Postretirement Plan-FAS 158	(1,816,365)							190	2,169,701	353,336
TOTAL	45,577,950	0	0	0	0				57,847307	103,425,257

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

	2014	Changes during Year				Adj Dr		Adj Cr		2014
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	End Bal k
EDC-Unrealized G/L from Rabbi Trust	535,261			15,954	8,185					543,030
SMSP-Unrealized G/L from Rabbi Trust	(22,448)			40,704	60,207					(41,951)
Royalty Income	325,457			24,230						349,687
Oregon Non-Op Prop Tax Adj	337			21	0					358
TOTAL	838,607	0	0	80,909	68,392		0		0	851,124

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	04/15/2015	End of 2014/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)	1,384,229	175	7,425,080	7,857,878	1,817,027
2	IPUC Order #28661					
3						
4	FAS 133 - Market to Market - (254203)	288,132	175	977,925	753,115	63,322
5	IPUC Order # 28661					
6						
7	Unfunded Accum Def Income Tax (254966)	50,788,060	various	825,696	852,362	50,814,726
8						
9	Idaho DSM Rider (254201)	6,685,745	various	51,643,514	44,175,538	-782,231
10	Order #29026					
11						
12	Oregon DSM Rider - (254202)	(3,694,183)	various	1,925,980	1,712,627	-3,907,536
13	Advise #05-03					
14						
15	Oregon Solar Pilot - (254005)	1,787,012	various	66,751	680,603	2,400,864
16	Order #10-198					
17						
18	Green Tags Oregon (254415)	22,807	1823	23,584	133,608	132,831
19	Order #11-086					
20						
21	Regulatory Unfunded Accum Def Income Tax (254419)	4,228,953			446,724	4,675,677
22						
23	Revenue Sharing (254101)	7,602,043	182	7,624,233	8,021,335	7,999,145
24	IPUC Order #32558					
25						
26	BPA Credit Residential Idaho (254401)	624,555	131/400	2,457,934	2,477,282	643,903
27	Advice # 11-03 (ID) #11-15 (OR)					
28						
29	WAQC Carryover (254901)	90,075	various	90,075	112,536	112,536
30	IPUC Order #29505					
31						
32	Bridger Depreciation #12-296 -(254800)	489,027	various		320,803	809,830
33						
34	Minor Items (7)	80,545	various	575,835	558,465	63,175
35						
36						
37						
38						
39						
40						
41	TOTAL	70,377,000		73,636,607	68,102,876	64,843,269

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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	500,194,726	513,914,273
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	453,982,593	436,445,539
5	Large (or Ind.) (See Instr. 4)	182,675,224	165,918,266
6	(444) Public Street and Highway Lighting	4,133,623	3,828,398
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,140,986,166	1,120,106,476
11	(447) Sales for Resale	77,164,887	54,472,513
12	TOTAL Sales of Electricity	1,218,151,053	1,174,578,989
13	(Less) (449.1) Provision for Rate Refunds	18,348,408	18,735,088
14	TOTAL Revenues Net of Prov. for Refunds	1,199,802,645	1,155,843,901
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	3,780,239	3,565,357
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	23,695,291	24,427,455
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	27,734,886	36,377,773
22	(456.1) Revenues from Transmission of Electricity of Others	22,627,916	21,936,382
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	77,838,332	86,306,967
27	TOTAL Electric Operating Revenues	1,277,640,977	1,242,150,868

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	04/15/2015	End of 2014/Q4

ELECTRIC OPERATING REVENUES (Account 400)

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

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
4,965,076	5,365,313	425,036	418,892	2
				3
5,877,580	6,040,697	84,425	83,439	4
3,217,070	3,181,866	116	117	5
32,641	31,478	2,380	2,205	6
				7
				8
				9
14,092,367	14,619,354	511,957	504,653	10
2,220,419	1,683,327			11
16,312,786	16,302,681	511,957	504,653	12
				13
16,312,786	16,302,681	511,957	504,653	14

Line 12, column (b) includes $ -6,191,476 of unbilled revenues.

Line 12, column (d) includes -75,221 MWH relating to unbilled revenues

Schedule Page: 300 Line No.: 17 Column: b

This amount consists of:

Service Establishment/Connection Charges (Includes late and after hour charges)	$2,953,981
Misc. Under $250,000	826,258
	3,780,239

Schedule Page: 300 Line No.: 21 Column: b

This amount consists of:

DSM Activity	$27,153,830
Stand-by-Service	321,995
Misc. Under $250,000	259,061
	27,734,886

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Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
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37					
38					
39					
40					
41					
42					
43					
44					
45					
46	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	04/15/2015	End of 2014/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	5,002,678	490,769,694	423,570	11,811	0.0981
3	03 - Residential Master Meter	4,234	396,120	22	192,455	0.0936
4	05 - Residential - TOD	24,949	2,355,949	1,444	17,278	0.0944
5	15 - Dusk to dawn lighting	2,670	651,491			0.2440
6	Unbilled Revenues	-69,455	-5,963,733			0.0859
7	Other Revenues		11,985,205			
8	Total 440	4,965,076	500,194,726	425,036	11,682	0.1007
9						
10	442-Commercial & Industrial Sales					
11	07 - General service	151,333	18,212,254	30,433	4,973	0.1203
12	09P - General service	475,373	30,601,202	208	2,285,447	0.0644
13	09S - General service	3,282,762	240,216,057	33,227	98,798	0.0732
14	09T - General service	6,268	449,941	4	1,567,000	0.0718
15	15 - Dusk to Dawn Light	4,144	742,891			0.1793
16	19P - Uniform rate contracts	2,236,085	129,042,450	109	20,514,541	0.0577
17	19S - Uniform rate contracts	6,279	403,268	1	6,279,000	0.0642
18	19T - Uniform rate contracts	120,445	7,091,329	3	40,148,333	0.0589
19	24S - Irrigation Pumping	1,966,297	155,477,335	19,692	99,853	0.0791
20	40 - General service	10,526	907,059	861	12,225	0.0862
21	Special Contracts	841,166	42,295,181	3	280,388,667	0.0503
22	Commercial & Industrial Unbill	-6,028	-261,363			0.0434
23	Other Revenues		11,480,213			
24	Total 442	9,094,650	636,657,817	84,541	107,577	0.0700
25						
26	444 - Public Street Lighting:					
27	40 - General service	1,120	96,802	450	2,489	0.0864
28	41 - Street lighting	28,403	3,753,574	1,450	19,588	0.1322
29	42 - Traffic control lighting	2,856	179,973	480	5,950	0.0630
30	Unbilled	262	33,620			0.1283
31	Other Revenues		69,654			
32	Total 444	32,641	4,133,623	2,380	13,715	0.1266
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	14,167,588	1,147,177,642	511,957	27,673	0.0810
42	Total Unbilled Rev.(See Instr. 6)	-75,221	-6,191,476	0	0	0.0823
43	TOTAL	14,092,367	1,140,986,166	511,957	27,526	0.0810

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	04/15/2015	End of 2014/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	Arizona Public Service Co.	SF	WSPP	n/a	n/a	n/a
2	Avista Corp.	SF	WSPP	n/a	n/a	n/a
3	Avista Corp.	OS	WSPP	n/a	n/a	n/a
4	Black Hills Power Inc.	SF	WSPP	n/a	n/a	n/a
5	Black Hills Power Inc.	OS	WSPP	n/a	n/a	n/a
6	Bonneville Power Administration	SF	WSPP	n/a	n/a	n/a
7	BP Energy Company	SF	WSPP	n/a	n/a	n/a
8	Cargill Power Markets LLC	OS	WSPP	n/a	n/a	n/a
9	Cargill Power Markets LLC	OS	WSPP	n/a	n/a	n/a
10	Cargill Power Markets LLC	OS	-	n/a	n/a	n/a
11	Cargill Power Markets LLC	SF	WSPP	n/a	n/a	n/a
12	Chelan County PUD	SF	WSPP	n/a	n/a	n/a
13	Citigroup Energy Inc.	SF	WSPP	n/a	n/a	n/a
14	Citigroup Energy Inc.	OS	-	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	04/15/2015	End of 2014/Q4

SALES FOR RESALE (Account 447)

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	City of Glendale	SF	WSPP	n/a	n/a	n/a
2	Clatskanie PUD	SF	WSPP	n/a	n/a	n/a
3	EDF Trading North America, LLC	SF	WSPP	n/a	n/a	n/a
4	EDF Trading North America, LLC	OS	WSPP	n/a	n/a	n/a
5	Eugene Electric Board	SF	WSPP	n/a	n/a	n/a
6	Exelon Generation Company. LLC	SF	WSPP	n/a	n/a	n/a
7	Grant County Public Utility District #2	SF	WSPP	n/a	n/a	n/a
8	IBERDROLA RENEWABLES, Inc.	OS	WSPP	n/a	n/a	n/a
9	IBERDROLA RENEWABLES, Inc.	SF	WSPP	n/a	n/a	n/a
10	IBERDROLA RENEWABLES, Inc.	OS	WSPP	n/a	n/a	n/a
11	J. Aron & Company	SF	WSPP	n/a	n/a	n/a
12	Jeffries Bache	OS	-	n/a	n/a	n/a
13	Los Angeles Department of Water & Power	SF	WSPP	n/a	n/a	n/a
14	Macquarie Energy LLC	OS	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
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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	Morgan Stanley Capital Group Inc.	SF	WSPP	n/a	n/a	n/a
2	Morgan Stanley Capital Group Inc.	OS	WSPP	n/a	n/a	n/a
3	Morgan Stanley Capital Group Inc.	OS	WSPP	n/a	n/a	n/a
4	Nevada Power Company, dba NVEnergy	OS	WSPP	n/a	n/a	n/a
5	Nevada Power Company, dba NVEnergy	SF	WSPP	n/a	n/a	n/a
6	Nevada Power Company, dba NVEnergy	OS	WSPP	n/a	n/a	n/a
7	NorthWestern Energy	SF	WSPP	n/a	n/a	n/a
8	PacifiCorp Inc.	SF	WSPP	n/a	n/a	n/a
9	PacifiCorp Inc.	OS	T-7	n/a	n/a	n/a
10	Portland General Electric Company	OS	WSPP	n/a	n/a	n/a
11	Platte River Power Authority	SF	WSPP	n/a	n/a	n/a
12	Portland General Electric Company	SF	WSPP	n/a	n/a	n/a
13	Powerex Corp.	OS	WSPP	n/a	n/a	n/a
14	Powerex Corp.	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	04/15/2015	End of 2014/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	PPL EnergyPlus, LLC	OS	WSPP	n/a	n/a	n/a
2	PPL EnergyPlus, LLC	SF	WSPP	n/a	n/a	n/a
3	Public Service Company of New Mexico	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	OS	WSPP	n/a	n/a	n/a
6	Rainbow Energy Marketing Corporation	SF	WSPP	n/a	n/a	n/a
7	Seattle City Light	OS	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.	OS	WSPP	n/a	n/a	n/a
10	Shell Energy North America (US), L.P.	SF	WSPP	n/a	n/a	n/a
11	Sierra Pacific Power Co., dba NV Energy	OS	T-7	n/a	n/a	n/a
12	Sierra Pacific Power Co., dba NV Energy	OS	WSPP	n/a	n/a	n/a
13	Sierra Pacific Power Co., dba NV Energy	SF	WSPP	n/a	n/a	n/a
14	Snohomish County PUD	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) 04/15/2015	Year/Period of Report End of 2014/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW): Average Monthly NCP Demand (e)	Actual Demand (MW): Average Monthly CP Demand (f)
1	Southern Cal Edison	OS	WSPP	n/a	n/a	n/a
2	Tenaska Power Services Co.	OS	WSPP	n/a	n/a	n/a
3	Tenaska Power Services Co.	SF	WSPP	n/a	n/a	n/a
4	The Energy Authority, Inc.	OS	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.	OS	WSPP	n/a	n/a	n/a
7	TransAlta Energy Marketing (U.S.) Inc.	SF	WSPP	n/a	n/a	n/a
8	Tucson Electric Power Company	SF	WSPP	n/a	n/a	n/a
9	Prior Year Adjustments	AD	-	n/a	n/a	n/a
10	Prior Year Write Off Recovered	AD	-	n/a	n/a	n/a
11	Oatt Rate Refund	AD	-	n/a	n/a	n/a
12	Transmission Penalty Distribution	AD	-	n/a	n/a	n/a
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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.
6,120		152,680		152,680	1
335,232		13,140,061		13,140,061	2
87		2,175		2,175	3
840		37,486		37,486	4
			19	19	5
164,019		5,521,287		5,521,287	6
2,800		72,661		72,661	7
			110,968	110,968	8
24		624		624	9
		-139,784		-139,784	10
14,283		371,629		371,629	11
245					12
56		2,450		2,450	13
		-204,360		-204,360	14
0	0	0	0	0	
2,220,419	0	75,567,752	1,597,135	77,164,887	
2,220,419	**0**	**75,567,752**	**1,597,135**	**77,164,887**	

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.
90,000		4,136,386		4,136,386	1
171		5,780		5,780	2
14,214		618,450		618,450	3
		310,492		310,492	4
4,968		178,749		178,749	5
136,951		4,554,931		4,554,931	6
24,237		774,364		774,364	7
			52,800	52,800	8
8,682		291,316		291,316	9
					10
38		1,772		1,772	11
		-2,792,018		-2,792,018	12
199,100		7,874,193		7,874,193	13
		-1,266,434		-1,266,434	14
0	0	0	0	0	
2,220,419	0	75,567,752	1,597,135	77,164,887	
2,220,419	**0**	**75,567,752**	**1,597,135**	**77,164,887**	

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.
80,777		2,537,545		2,537,545	1
20		480		480	2
			448,193	448,193	3
			32,446	32,446	4
133,404		3,587,355		3,587,355	5
480		16,320		16,320	6
34,795		1,733,573		1,733,573	7
23,423		866,793		866,793	8
69		2,217		2,217	9
			38,873	38,873	10
17		935		935	11
67,585		2,494,290		2,494,290	12
785		17,831		17,831	13
48,415		1,369,537		1,369,537	14
0	0	0	0	0	
2,220,419	0	75,567,752	1,597,135	77,164,887	
2,220,419	**0**	**75,567,752**	**1,597,135**	**77,164,887**	

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.
			40,180	40,180	1
9,363		336,618		336,618	2
100		3,200		3,200	3
12,478		519,293		519,293	4
			15,593	15,593	5
49,536		1,452,174		1,452,174	6
215		6,450		6,450	7
17,638		622,449		622,449	8
			754,958	754,958	9
265,522		9,244,324		9,244,324	10
49		1,819		1,819	11
			3,715	3,715	12
800		24,550		24,550	13
430		13,280		13,280	14
0	0	0	0	0	
2,220,419	0	75,567,752	1,597,135	77,164,887	
2,220,419	**0**	**75,567,752**	**1,597,135**	**77,164,887**	

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.
			735	735	1
			10,950	10,950	2
20,513		514,208		514,208	3
			3,373	3,373	4
427,455		15,851,245		15,851,245	5
			72,656	72,656	6
23,727		680,341		680,341	7
754		26,035		26,035	8
2					9
			10,822	10,822	10
			-2,523	-2,523	11
			3,377	3,377	12
					13
					14
0	0	0	0	0	
2,220,419	0	75,567,752	1,597,135	77,164,887	
2,220,419	**0**	**75,567,752**	**1,597,135**	**77,164,887**	

Schedule Page: 310 Line No.: 3 Column: b
Non-firm Sales
Schedule Page: 310 Line No.: 5 Column: b
Financial Transmission Losses
Schedule Page: 310 Line No.: 8 Column: b
Financial Transmission Losses
Schedule Page: 310 Line No.: 9 Column: b
Non-firm Sales
Schedule Page: 310 Line No.: 10 Column: b
ISDA Master Agreement with Cargill Power Markets LLC, dated June 13, 2011
Schedule Page: 310 Line No.: 14 Column: b
ISDA Master Agreement with Citigroup Energy, Inc., dated March 7, 2011
Schedule Page: 310.1 Line No.: 4 Column: b
ISDA Master Agreement with EDF Trading North America, LLC, dated October 25, 2012.
Schedule Page: 310.1 Line No.: 8 Column: b
Financial Transmission Losses
Schedule Page: 310.1 Line No.: 10 Column: b
Non-firm Sales
Schedule Page: 310.1 Line No.: 12 Column: b
Prudential Bache Commodities (Jeffries Bache), LLC Futures Account Document, dated September 4, 2008
Schedule Page: 310.1 Line No.: 14 Column: b
ISDA Master Agreement with Macquarie Energy, LLC dated April 12, 2011
Schedule Page: 310.2 Line No.: 2 Column: b
Non-firm Sales
Schedule Page: 310.2 Line No.: 3 Column: b
Financial Transmission Losses
Schedule Page: 310.2 Line No.: 4 Column: b
Financial Transmission Losses
Schedule Page: 310.2 Line No.: 6 Column: b
Unit Contingent Sales
Schedule Page: 310.2 Line No.: 9 Column: b
Spinning or Operating Reserves
Schedule Page: 310.2 Line No.: 10 Column: b
Financial Transmission Losses
Schedule Page: 310.2 Line No.: 13 Column: b
Non-firm Sales
Schedule Page: 310.3 Line No.: 1 Column: b
Financial Transmission Losses
Schedule Page: 310.3 Line No.: 5 Column: b
Financial Transmission Losses
Schedule Page: 310.3 Line No.: 7 Column: b
Non-firm Sales
Schedule Page: 310.3 Line No.: 9 Column: b
Financial Transmission Losses
Schedule Page: 310.3 Line No.: 11 Column: b
Spinning or Operating Reserves
Schedule Page: 310.3 Line No.: 12 Column: b
Financial Transmission Losses
Schedule Page: 310.4 Line No.: 1 Column: b
Financial Transmission Losses
Schedule Page: 310.4 Line No.: 2 Column: b

Financial Transmission Losses

Schedule Page: 310.4 Line No.: 4 Column: b

Financial Transmission Losses

Schedule Page: 310.4 Line No.: 6 Column: b

Financial Transmission Losses

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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	1,376,709	1,524,957
5	(501) Fuel	156,172,175	160,276,741
6	(502) Steam Expenses	8,741,266	8,840,885
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,599,507	1,741,112
10	(506) Miscellaneous Steam Power Expenses	9,598,723	9,473,766
11	(507) Rents	530,520	348,322
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	178,018,900	182,205,783
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	277,886	101,619
16	(511) Maintenance of Structures	708,308	637,844
17	(512) Maintenance of Boiler Plant	10,923,064	12,461,886
18	(513) Maintenance of Electric Plant	6,044,954	5,398,984
19	(514) Maintenance of Miscellaneous Steam Plant	5,806,415	4,541,443
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	23,760,627	23,141,776
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	201,779,527	205,347,559
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	5,700,460	6,034,727
45	(536) Water for Power	7,316,134	5,679,423
46	(537) Hydraulic Expenses	14,097,825	13,572,536
47	(538) Electric Expenses	1,530,453	1,432,669
48	(539) Miscellaneous Hydraulic Power Generation Expenses	5,732,591	4,855,798
49	(540) Rents	259,705	141,597
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	34,637,168	31,716,750
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	122,182	83,805
54	(542) Maintenance of Structures	1,387,369	1,427,309
55	(543) Maintenance of Reservoirs, Dams, and Waterways	366,307	1,148,299
56	(544) Maintenance of Electric Plant	2,279,584	2,617,210
57	(545) Maintenance of Miscellaneous Hydraulic Plant	2,554,638	3,005,680
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	6,710,080	8,282,303
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	41,347,248	39,999,053

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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	813,875	1,360,914
63	(547) Fuel	45,068,831	54,204,949
64	(548) Generation Expenses	3,596,219	3,427,130
65	(549) Miscellaneous Other Power Generation Expenses	905,574	585,699
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	50,384,499	59,578,692
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		99
70	(552) Maintenance of Structures	378,067	301,287
71	(553) Maintenance of Generating and Electric Plant	86,516	131,162
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	1,391,428	1,233,983
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	1,856,011	1,666,531
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	52,240,510	61,245,223
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	237,121,899	214,941,823
77	(556) System Control and Load Dispatching	-1,242	1,403,451
78	(557) Other Expenses	25,139,587	-34,629,989
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	262,260,244	181,715,285
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	557,627,529	488,307,120
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	4,019,284	3,560,221
84			
85	(561.1) Load Dispatch-Reliability	55,425	39,635
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,673,701	1,702,334
87	(561.3) Load Dispatch-Transmission Service and Scheduling	926,555	1,036,729
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	38,422	94,561
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	2,458,270	2,403,457
94	(563) Overhead Lines Expenses	669,240	732,402
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	6,081,299	5,637,278
97	(566) Miscellaneous Transmission Expenses	18,274	49,579
98	(567) Rents	3,284,850	2,917,528
99	TOTAL Operation (Enter Total of lines 83 thru 98)	19,225,320	18,173,724
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	169,505	323,417
102	(569) Maintenance of Structures	26,645	7,617
103	(569.1) Maintenance of Computer Hardware	9,454	7,491
104	(569.2) Maintenance of Computer Software	960,142	734,188
105	(569.3) Maintenance of Communication Equipment	42,031	4,564
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	3,702,550	3,610,183
108	(571) Maintenance of Overhead Lines	3,198,420	3,588,427
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	1,593	607
111	TOTAL Maintenance (Total of lines 101 thru 110)	8,110,340	8,276,494
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	27,335,660	26,450,218

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	4,028,859	4,160,840
135	(581) Load Dispatching	3,643,133	3,529,347
136	(582) Station Expenses	1,180,321	1,375,049
137	(583) Overhead Line Expenses	3,138,798	3,111,427
138	(584) Underground Line Expenses	2,525,008	2,402,213
139	(585) Street Lighting and Signal System Expenses	76,902	74,337
140	(586) Meter Expenses	4,424,696	4,421,678
141	(587) Customer Installations Expenses	694,859	673,959
142	(588) Miscellaneous Expenses	5,788,865	5,754,224
143	(589) Rents	466,127	366,175
144	TOTAL Operation (Enter Total of lines 134 thru 143)	25,967,568	25,869,249
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	16,451	168,884
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	3,950,824	3,816,291
149	(593) Maintenance of Overhead Lines	13,906,165	14,492,291
150	(594) Maintenance of Underground Lines	630,375	645,600
151	(595) Maintenance of Line Transformers	148,125	286,874
152	(596) Maintenance of Street Lighting and Signal Systems	531,740	536,040
153	(597) Maintenance of Meters	735,448	750,543
154	(598) Maintenance of Miscellaneous Distribution Plant	418,635	412,978
155	TOTAL Maintenance (Total of lines 146 thru 154)	20,337,763	21,109,501
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	46,305,331	46,978,750
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	503,846	491,363
160	(902) Meter Reading Expenses	1,698,642	1,484,232
161	(903) Customer Records and Collection Expenses	16,630,398	14,060,136
162	(904) Uncollectible Accounts	6,715,796	5,805,414
163	(905) Miscellaneous Customer Accounts Expenses	95	271
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	25,548,777	21,841,416

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	593,673	531,496
168	(908) Customer Assistance Expenses	34,149,782	42,690,734
169	(909) Informational and Instructional Expenses	374,524	264,701
170	(910) Miscellaneous Customer Service and Informational Expenses	696,365	574,875
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	35,814,344	44,061,806
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	73,163,837	69,143,869
182	(921) Office Supplies and Expenses	17,437,094	17,610,990
183	(Less) (922) Administrative Expenses Transferred-Credit	27,257,584	26,882,864
184	(923) Outside Services Employed	4,705,146	5,271,865
185	(924) Property Insurance	3,461,411	3,673,489
186	(925) Injuries and Damages	6,125,055	5,694,399
187	(926) Employee Pensions and Benefits	61,971,169	62,531,128
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	3,457,838	3,975,664
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	453,160	496,936
192	(930.2) Miscellaneous General Expenses	4,907,415	4,246,371
193	(931) Rents	176	6,536
194	TOTAL Operation (Enter Total of lines 181 thru 193)	148,424,717	145,768,383
195	Maintenance		
196	(935) Maintenance of General Plant	7,508,482	5,252,115
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	155,933,199	151,020,498
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	848,564,840	778,659,808

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	04/15/2015	End of 2014/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	AgPower Jerome / Double A Digester	LU	-	N/A	N/A	N/A
2	Allan Ravenscroft/Malad River	LU	-	.488Mw		
3	Bannock County, Idaho	LU	-	N/A	N/A	N/A
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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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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 Wind Farm	LU	-	N/A	N/A	N/A
4	City of Cove, Oregon / Mill Creek	LU	-	N/A	N/A	N/A
5	City of Hailey	LU	-	N/A	N/A	N/A
6	City of Pocatello	LU	-	N/A	N/A	N/A
7	Clear Springs Food Inc.	LU	-	N/A	N/A	N/A
8	Clifton E. Jenson/Birch Creek	LU	-	.05Mw		
9	Cold Springs Windfarm, LLC	LU	-	N/A	N/A	N/A
10	Consolidated Hydro Inc. / Enel		-			
11	Barber Dam	LU	-	N/A	N/A	N/A
12	Dietrich Drop	LU	-	N/A	N/A	N/A
13	GeoBon #2	LU	-	N/A	N/A	N/A
14	Lowline #2	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	04/15/2015	End of 2014/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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	Rock Creek #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	-	.084Mw		
5	David McCollum/Canyon Springs	LU	-	N/A	N/A	N/A
6	David R Snedigar	LU	-	N/A	N/A	N/A
7	Desert Meadow Wind Farm	LU	-	N/A	N/A	N/A
8	Eightmile Hydro Corp	LU	-	N/A	N/A	N/A
9	Faulkner Brothers Hydro Inc.	LU	-	N/A	N/A	N/A
10	Fisheries Development	OS	-	N/A	N/A	N/A
11	Fossil Gulch Wind	LU	-	N/A	N/A	N/A
12	G2 Energy Hidden Hollow	LU	-	N/A	N/A	N/A
13	Golden Valley Wind Park	LU	-	N/A	N/A	N/A
14	Hammett Hill Windfarm, LLC	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	04/15/2015	End of 2014/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.
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3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

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

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Lateral 10 Ventures	LU	-	N/A	N/A	N/A
2	Lemhi Hydro Power Co./Schaffner	LU	-	N/A	N/A	N/A
3	Lime Wind	LU	-	N/A	N/A	N/A
4	Little Mac Power Co./Cedar Draw	LU	-	N/A	N/A	N/A
5	Little Wood River Irrigation District	LU	-	N/A	N/A	N/A
6	Magic Reservoir Hydro	LU	-	N/A	N/A	N/A
7	Mainline Windfarm	LU	-	N/A	N/A	N/A
8	Marco Rancher's Irrigation Inc.	LU	-	N/A	N/A	N/A
9	Marysville Hydro Partners/Falls River	LU	-	N/A	N/A	N/A
10	Milner Dam Wind Park	LU	-	N/A	N/A	N/A
11	Mud Creek White Hydro, Inc	LU	-	N/A	N/A	N/A
12	New Energy One / Rock Creek Dairy	LU	-	N/A	N/A	N/A
13	Oregon Trail Wind Park	LU	-	N/A	N/A	N/A
14	Owyhee Irrigation District					
	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	04/15/2015	End of 2014/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Mitchell Butte	LU	-	N/A	N/A	N/A
2	Owyhee Dam	LU	-	N/A	N/A	N/A
3	Paynes Ferry Wind Park	LU	-	N/A	N/A	N/A
4	Pigeon Cove Power	LU	-	1.389		
5	Pilgrim Stage Station Wind Park	LU	-	N/A	N/A	N/A
6	Pristine Springs Inc #1	LU	-	N/A	N/A	N/A
7	Pristine Springs Inc. #3	LU	-	N/A	N/A	N/A
8	Reynolds Irrigation District	LU	-	N/A	N/A	N/A
9	Richard Kaster					
10	Box Canyon	LU	-	N/A	N/A	N/A
11	Briggs Creek	LU	-	N/A	N/A	N/A
12	Riverside Hydro/Mora Drop	LU	-	N/A	N/A	N/A
13	Riverside Investments					
14	Arena 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	04/15/2015	End of 2014/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Fargo Drop	LU	-	N/A	N/A	N/A
2	Rock Creek #1 Joint Venture	LU	-	1.732Mw		
3	Rockland Wind Project	LU	-	N/A	N/A	N/A
4	Rupert Cogeneration Partners/Magic Val	LU	-	N/A	N/A	N/A
5	Ryegrass Windfarm	LU	-	N/A	N/A	N/A
6	Salmon Falls Wind Park	LU	-	N/A	N/A	N/A
7	SE Hazelton A LP	LU	-	N/A	N/A	N/A
8	Shorock Hydro Inc.					
9	Shoshone CSPP	LU	-	N/A	N/A	N/A
10	Shoshone #2	LU	-	N/A	N/A	N/A
11	Snake River Pottery	LU	-	N/A	N/A	N/A
12	South Forks Joint Venture/Lowline Cana	LU	-	N/A	N/A	N/A
13	Tamarack Energy Partnership	LU	-	4.942Mw		
14	Tasco - Nampa	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	04/15/2015	End of 2014/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	Tasco - Twin Falls	OS	-	N/A	N/A	N/A
2	Ted S. Sorenson/Tiber Dam	LU	-	N/A	N/A	N/A
3	Thousand Springs Wind Park	LU	-	N/A	N/A	N/A
4	Tuana Gulch Wind Park	LU	-	N/A	N/A	N/A
5	Tuana Springs Expansion	LU	-	N/A	N/A	N/A
6	Twin Falls Energy/Lowline Midway Hydro	LU	-	N/A	N/A	N/A
7	Two Ponds Windfarm	LU	-	N/A	N/A	N/A
8	White Water Ranch	LU	-	N/A	N/A	N/A
9	William Arkoosh/Littlewood	LU	-	N/A	N/A	N/A
10	Willis and Betty Deveny/Shingle Creek	LF	-	N/A	N/A	N/A
11	Wilson Power Company	LU	-	N/A	N/A	N/A
12	Yahoo Creek Wind Park	LU	-	N/A	N/A	N/A
13	Prior Period Overpayment Recovery	OS	-	N/A	N/A	N/A
14	Scheduling Deviation	OS	-			
	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	04/15/2015	End of 2014/Q4

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1	Other Purchased Power					
2	Arizona Public Service Co.	SF	WSPP	N/A	N/A	N/A
3	Avista Corp.	OS	T-12	N/A	N/A	N/A
4	Avista Corp.	SF	WSPP	N/A	N/A	N/A
5	Avista Corp.	OS	WSPP	N/A	N/A	N/A
6	Black Hills Power Inc.	SF	WSPP	N/A	N/A	N/A
7	Bonneville Power Administration	OS	WSPP	N/A	N/A	N/A
8	Bonneville Power Administration	OS	WSPP	N/A	N/A	N/A
9	Bonneville Power Administration	SF	WSPP	N/A	N/A	N/A
10	BP Energy Company	SF	WSPP	N/A	N/A	N/A
11	Calpine Energy Services, L.P.	SF	WSPP	N/A	N/A	N/A
12	Cargill Power Markets LLC	SF	WSPP	N/A	N/A	N/A
13	Chelan Co PUD	OS	WSPP	N/A	N/A	N/A
14	Citigroup Energy Inc.	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) 04/15/2015	Year/Period of Report End of 2014/Q4

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1	Citigroup Energy Inc.	OS	-	N/A	N/A	N/A
2	City of Glendale	SF	WSPP	N/A	N/A	N/A
3	Clatskanie PUD	SF	WSPP	N/A	N/A	N/A
4	Constellation Energy Control and Dispa	OS	WSPP	N/A	N/A	N/A
5	EDF Trading North America, LLC	SF	WSPP	N/A	N/A	N/A
6	Eugene Water & Electric Board	SF	WSPP	N/A	N/A	N/A
7	Exelon Generation Company, LLC	SF	WSPP	N/A	N/A	N/A
8	Grant CO Public Utility District #2 --	OS	WSPP	N/A	N/A	N/A
9	Grant CO Public Utility District #2 --	SF	WSPP	N/A	N/A	N/A
10	IBERDROLA RENEWABLES, Inc.	SF	WSPP	N/A	N/A	N/A
11	J. Aron & Company	SF	WSPP	N/A	N/A	N/A
12	J.P. Morgan Ventures Energy Corporatio	SF	WSPP	N/A	N/A	N/A
13	Jefferies Bache	OS	-	N/A	N/A	N/A
14	Los Angeles Dept of Water & Power - En	SF	WSPP	N/A	N/A	N/A
	Total					

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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	Municipal Energy Agency of Nebraska	SF	WSPP	N/A	N/A	N/A
2	Morgan Stanley Capital Group Inc.	SF	ISDA	N/A	N/A	N/A
3	Nevada Power Company, DBA NV Energy	SF	WSPP	N/A	N/A	N/A
4	NorthWestern Energy	OS	T-7	N/A	N/A	N/A
5	NorthWestern Energy	SF	WSPP	N/A	N/A	N/A
6	PacifiCorp Inc.	OS	T-13	N/A	N/A	N/A
7	PacifiCorp Inc.	SF	WSPP	N/A	N/A	N/A
8	PacifiCorp Inc.	OS	WSPP	N/A	N/A	N/A
9	Portland General Electric Company	OS	T-14	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	PPL EnergyPlus, LLC	SF	WSPP	N/A	N/A	N/A
13	PPL EnergyPlus, LLC	OS	WSPP	N/A	N/A	N/A
14	Public Service Company of New Mexico	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	04/15/2015	End of 2014/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	Puget Sound Energy, Inc.	OS	T-9	N/A	N/A	N/A
2	Puget Sound Energy, Inc.	SF	WSPP	N/A	N/A	N/A
3	Rainbow Energy Marketing Corporation	SF	WSPP	N/A	N/A	N/A
4	Salt River Project	SF	WSPP	N/A	N/A	N/A
5	Seattle City Light	OS	WSPP	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	Shell Energy North America (US), L.P.	SF	WSPP	N/A	N/A	N/A
9	Sierra Pacific Power Co., dba NV Energ	OS	T-55	N/A	N/A	N/A
10	Snohomish County PUD	SF	WSPP	N/A	N/A	N/A
11	Tacoma Power	OS	WSPP	N/A	N/A	N/A
12	Tacoma Power	SF	WSPP	N/A	N/A	N/A
13	Tenaska Power Services Co.	SF	WSPP	N/A	N/A	N/A
14	The Energy Authority, Inc.	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	04/15/2015	End of 2014/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	TransAlta Energy Marketing (U.S.) Inc.	SF	WSPP	N/A	N/A	N/A
2	Turlock Irrigation District	SF	WSPP	N/A	N/A	N/A
3	Raft River Energy I LLC	LU	-	N/A	N/A	N/A
4	Telocaset Wind Power Partners LLC	LU	APP-A	N/A	N/A	N/A
5	Neal Hot Springs Unit #1	LU	-	N/A	N/A	N/A
6	Net Metering Customers	OS	-	N/A	N/A	N/A
7	Oregon Solar Customers	OS	-	N/A	N/A	N/A
8	Prior Year Adjustments	AD	-	N/A	N/A	N/A
9	Prior Year Adjustments	OS	-	N/A	N/A	N/A
10	Power Exchanges		-			
11	Bonneville Power Administration	EX	-			
12	NorthWestern Energy	EX	-			
13	PacifiCorp Inc.	EX	-			
14	Powerex Corp.	EX	-			
	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	04/15/2015	End of 2014/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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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.

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Sierra Pacific Power Co., dba NV Energ	EX	-			
2	Clatskanie PUD	EX	153			
3	Other Transactions					
4	Acctg Valuation of Clatskanie PUD					
5	Demand Response Avoided Energy	OS	-	N/A	N/A	N/A
6	Clark Canyon Damages	OS	-	N/A	N/A	N/A
7	PacifiCorp Loss Repayment	OS	-	N/A	N/A	N/A
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)	
27,305				2,267,324		2,267,324	1
1,604			155,672	62,590		218,262	2
4,816				208,408		208,408	3
44,719				2,688,291		2,688,291	4
13,455				1,094,933		1,094,933	5
8,762				517,645		517,645	6
							7
333				23,357		23,357	8
953				68,977		68,977	9
964				69,618		69,618	10
3,366				347,470		347,470	11
693				48,651		48,651	12
61,275				3,334,374		3,334,374	13
27,052				1,464,756		1,464,756	14
4,148,611	324,803	211,221	2,815,124	232,321,276	1,985,499	237,121,899	

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)	
66,813				5,615,388		5,615,388	1
8,468				702,326		702,326	2
26,647				1,525,090		1,525,090	3
3,702				270,590		270,590	4
50				3,580		3,580	5
1,407				104,145		104,145	6
3,532				333,945		333,945	7
321			17,500	12,434		29,934	8
53,793				3,502,993		3,502,993	9
							10
10,349				538,180		538,180	11
15,142				839,625		839,625	12
3,064				234,774		234,774	13
7,654				419,399		419,399	14
4,148,611	324,803	211,221	2,815,124	232,321,276	1,985,499	237,121,899	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
6,828				358,045		358,045	1
4,755				334,097		334,097	2
10,437				704,700		704,700	3
638			26,796	25,316		52,112	4
521				15,563		15,563	5
1,346				93,905		93,905	6
62,680				4,069,461		4,069,461	7
139				7,438		7,438	8
3,265				253,809		253,809	9
1,152				35,623		35,623	10
24,775				1,389,340		1,389,340	11
18,259				1,123,012		1,123,012	12
34,007				1,843,655		1,843,655	13
60,610				3,942,261		3,942,261	14
4,148,611	324,803	211,221	2,815,124	232,321,276	1,985,499	237,121,899	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
22,826				1,613,586		1,613,586	1
97,693				4,616,740		4,616,740	2
1,615				135,121		135,121	3
44,794				3,107,261		3,107,261	4
19,321				1,071,969		1,071,969	5
41,453				2,475,077		2,475,077	6
59,691				4,617,988		4,617,988	7
74,878				3,744,319		3,744,319	8
1,130				80,206		80,206	9
4,192				296,037		296,037	10
626				35,417		35,417	11
3,494				306,397		306,397	12
5,900				482,669		482,669	13
2,906				269,371		269,371	14
4,148,611	324,803	211,221	2,815,124	232,321,276	1,985,499	237,121,899	

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)	
7,567				487,034		487,034	1
1,273				98,057		98,057	2
5,817				426,161		426,161	3
6,002				391,208		391,208	4
2,071				143,368		143,368	5
5,806				278,193		278,193	6
59,185				3,844,357		3,844,357	7
2,196				149,801		149,801	8
54,155				3,646,985		3,646,985	9
59,061				3,202,889		3,202,889	10
460				30,610		30,610	11
13,390				1,020,631		1,020,631	12
38,403				2,096,620		2,096,620	13
							14
4,148,611	324,803	211,221	2,815,124	232,321,276	1,985,499	237,121,899	

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
96				2,903		2,903	1
10,655				260,408		260,408	2
63,921				5,374,826		5,374,826	3
8,482			486,150	290,674		776,824	4
33,185				1,809,265		1,809,265	5
808				49,850		49,850	6
1,231				65,916		65,916	7
1,259				94,590		94,590	8
							9
2,049				136,478		136,478	10
3,668				251,069		251,069	11
4,916				285,491		285,491	12
							13
1,578				126,368		126,368	14
4,148,611	324,803	211,221	2,815,124	232,321,276	1,985,499	237,121,899	

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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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)	
3,487				162,914		162,914	1
9,163			552,508	361,700		914,208	2
263,174				16,003,917		16,003,917	3
76,713				5,076,275		5,076,275	4
56,392				3,660,876		3,660,876	5
65,142				3,534,112		3,534,112	6
23,682				1,652,669		1,652,669	7
							8
1,427				128,652		128,652	9
2,113				151,502		151,502	10
334				22,835		22,835	11
29,140				2,108,441		2,108,441	12
28,870			1,576,498	1,309,257		2,885,755	13
84				2,162		2,162	14
4,148,611	324,803	211,221	2,815,124	232,321,276	1,985,499	237,121,899	

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES: MegaWatt Hours Received (h)	POWER EXCHANGES: MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER: Demand Charges ($) (j)	COST/SETTLEMENT OF POWER: Energy Charges ($) (k)	COST/SETTLEMENT OF POWER: Other Charges ($) (l)	COST/SETTLEMENT OF POWER: Total (j+k+l) of Settlement ($) (m)	Line No.
1				33		33	1
28,813				1,564,466		1,564,466	2
32,787				1,799,288		1,799,288	3
30,056				1,642,697		1,642,697	4
79,036				4,351,059		4,351,059	5
8,810				541,845		541,845	6
62,355				4,024,407		4,024,407	7
654				44,886		44,886	8
3,157				241,027		241,027	9
928				70,342		70,342	10
26,527				1,878,057		1,878,057	11
65,032				5,441,691		5,441,691	12
				-1,884,407		-1,884,407	13
-4,830							14
4,148,611	324,803	211,221	2,815,124	232,321,276	1,985,499	237,121,899	

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	04/15/2015	End of 2014/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.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
393				7,963		7,963	2
11				258		258	3
135,562				3,779,679		3,779,679	4
					249,576	249,576	5
75				3,225		3,225	6
					678,417	678,417	7
111				2,534		2,534	8
78,087				2,551,020		2,551,020	9
8,000				102,000		102,000	10
219				-595		-595	11
8,437				293,515		293,515	12
4				108		108	13
151,200				6,818,064		6,818,064	14
4,148,611	324,803	211,221	2,815,124	232,321,276	1,985,499	237,121,899	

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
					-104,044	-104,044	1
38				1,772		1,772	2
325				3,592		3,592	3
2				79		79	4
115,825				4,322,798		4,322,798	5
2,842				76,859		76,859	6
8,817				77,358		77,358	7
5				148		148	8
175				8,225		8,225	9
92,730				2,951,306		2,951,306	10
62,400				2,691,169		2,691,169	11
20,800				1,076,400		1,076,400	12
					1,520,390	1,520,390	13
252				8,403		8,403	14
4,148,611	324,803	211,221	2,815,124	232,321,276	1,985,499	237,121,899	

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	04/15/2015	End of 2014/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.

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	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
30				1,260		1,260	1
88,123				3,519,175		3,519,175	2
6,319				285,274		285,274	3
9				258		258	4
5,545				165,077		165,077	5
73				1,744		1,744	6
5,593				175,683		175,683	7
					180,673	180,673	8
10				354		354	9
10,507				366,566		366,566	10
125,810				4,137,949		4,137,949	11
206,278				6,532,457		6,532,457	12
75				3,375		3,375	13
2,875				135,335		135,335	14
4,148,611	324,803	211,221	2,815,124	232,321,276	1,985,499	237,121,899	

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.

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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)	
15				446		446	1
15,227				419,651		419,651	2
6,497				220,226		220,226	3
110				5,250		5,250	4
6				150		150	5
400				12,396		12,396	6
12,977				416,270		416,270	7
7,243				216,694		216,694	8
41				952		952	9
1,397				16,955		16,955	10
2				69		69	11
400				18,025		18,025	12
547				20,704		20,704	13
25,626				470,756		470,756	14
4,148,611	324,803	211,221	2,815,124	232,321,276	1,985,499	237,121,899	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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)	
11,907				397,120		397,120	1
4,108				52,933		52,933	2
78,916				4,987,942		4,987,942	3
292,788				16,446,275		16,446,275	4
183,529				18,747,659		18,747,659	5
544				214		214	6
696				27,804		27,804	7
2							8
					-2,453	-2,453	9
							10
	69,122						11
	19,041	977					12
	163,705	137,305					13
	277						14
4,148,611	324,803	211,221	2,815,124	232,321,276	1,985,499	237,121,899	

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)	
		4,764					1
	72,658	68,175					2
							3
					-163,570	-163,570	4
				7,940,697		7,940,697	5
					-373,490	-373,490	6
81,625							7
							8
							9
							10
							11
							12
							13
							14
4,148,611	324,803	211,221	2,815,124	232,321,276	1,985,499	237,121,899	

Schedule Page: 326 Line No.: 2 Column: e
Unavailable
Schedule Page: 326 Line No.: 2 Column: f
Unavailable
Schedule Page: 326.1 Line No.: 8 Column: e
Unavailable
Schedule Page: 326.1 Line No.: 8 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.: 10 Column: b
Non Firm Purchases
Schedule Page: 326.3 Line No.: 1 Column: a
Ida West, a subsidiary of Idaho Power Company, has partial ownership of these projects.
Schedule Page: 326.5 Line No.: 4 Column: e
Unavailable
Schedule Page: 326.5 Line No.: 4 Column: f
Unavailable
Schedule Page: 326.6 Line No.: 2 Column: e
Unavailable
Schedule Page: 326.6 Line No.: 2 Column: f
Unavailable
Schedule Page: 326.6 Line No.: 12 Column: a
Ida West, a subsidiary of Idaho Power Company, has partial ownership of these projects.
Schedule Page: 326.6 Line No.: 13 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.: 13 Column: e
Unavailable
Schedule Page: 326.6 Line No.: 13 Column: f
Unavailable
Schedule Page: 326.6 Line No.: 14 Column: b
Non Firm Purchases
Schedule Page: 326.7 Line No.: 1 Column: b
Non Firm Purchases
Schedule Page: 326.7 Line No.: 11 Column: a
Ida West, a subsidiary of Idaho Power Company, has partial ownership of these projects.
Schedule Page: 326.7 Line No.: 13 Column: a
Prior Period Overpayment Recovery (JR Simplot)
Schedule Page: 326.7 Line No.: 14 Column: a
Difference between booked and scheduled energy
Schedule Page: 326.8 Line No.: 3 Column: b
Non Firm Purchases
Schedule Page: 326.8 Line No.: 5 Column: b
Financial Transmission Losses
Schedule Page: 326.8 Line No.: 7 Column: b
Financial Transmission losses
Schedule Page: 326.8 Line No.: 8 Column: b
Non Firm Purchases
Schedule Page: 326.8 Line No.: 13 Column: b

Non Firm Purchases

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

ISDA Naster Agreement with Citigroup Energy PLC dated March 7, 2011.

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

Non Firm Purchases

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

Non Firm Purchases

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

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

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

Non Firm Purchases

Schedule Page: 326.10 Line No.: 6 Column: b

Non Firm Purchases

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

Financial Transmission Losses

Schedule Page: 326.10 Line No.: 9 Column: b

Non Firm Purchases

Schedule Page: 326.10 Line No.: 13 Column: b

Non Firm Purchases

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

Non Firm Purchases

Schedule Page: 326.11 Line No.: 5 Column: b

Non Firm Purchases

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

Non Firm Purchases

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

Non Firm Purchases

Schedule Page: 326.11 Line No.: 11 Column: b

Non Firm Purchases

Schedule Page: 326.12 Line No.: 3 Column: b

Unavailable

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

Schedule 84 Net Metering

Schedule Page: 326.12 Line No.: 7 Column: b

Schedule 88 Oregon Solar

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

Financial Transmission Losses

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

Financial Transmission losses

Schedule Page: 326.12 Line No.: 12 Column: b

Financial Transmission Losses

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

Financial Transmission losses

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

Financial Transmission Losses

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

Financial Transmission Losses

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Bonneville Power Administration - OTEC	Bonneville Power Administration	Oregon Trails Electric Co-op	FNO
2	Bonneville Power Administration - OTEC	Bonneville Power Administration	Oregon Trails Electric Co-op	AD
3	Bonneville Power Administration - USBR	Bonneville Power Administration	United States Bureau of Reclamati	FNO
4	Bonneville Power Administration - USBR	Bonneville Power Administration	United States Bureau of Reclamati	AD
5	Bonneville Power Administration - PF	Bonneville Power Administration	Priority Firm Customers	FNO
6	Bonneville Power Administration - PF	Bonneville Power Administration	Priority Firm Customers	AD
7	Bonneville Power Administration - Raft	Bonneville Power Administration	Raft River Idaho Customers	AD
8	Milner Irrigation District	United States Bureau of Reclamati	Milner Irrigation District	OLF
9	Shell Energy North America (US), L.P.	Seattle City Light	Bonneville Power Administration	OS
10	PacifiCorp	PacifiCorp West	PacifiCorp West	FNO
11	PacifiCorp	PacifiCorp West	PacifiCorp West	AD
12	United States Bureau of Indian Affairs	Bonneville Power Administration	United States Bureau of Indian Af	OS
13	United Materials of Great Falls	NorthWestern/PacifiCorp East	Idaho Power Company	OS
14	United Materials of Great Falls	PacifiCorp East	Idaho Power Company	OS
15	Avista Corporation	NorthWestern/PacifiCorp East	Avista	NF
16	Avista Corporation			AD
17	Black Hills Power Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
18	Black Hills Power Inc.			AD
19	Bonneville Power Administration	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
20	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	NF
21	Bonneville Power Administration	Bonneville Power Administration	Sierra Pacific Power	NF
22	Bonneville Power Administration	Avista	Bonneville Power Administration	NF
23	Bonneville Power Administration	Avista	Sierra Pacific Power	NF
24	Bonneville Power Administration			AD
25	Cargill Power Markets LLC	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
26	Cargill Power Markets LLC	PacifiCorp East	NorthWestern/PacifiCorp East	NF
27	Cargill Power Markets LLC	PacifiCorp East	Bonneville Power Administration	NF
28	Cargill Power Markets LLC	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
29	Cargill Power Markets LLC	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
30	Cargill Power Markets LLC	PacifiCorp East	Sierra Pacific Power	NF
31	Cargill Power Markets LLC	PacifiCorp West	PacifiCorp East	NF
32	Cargill Power Markets LLC	PacifiCorp West	PacifiCorp East	SFP
33	Cargill Power Markets LLC	PacifiCorp West	Sierra Pacific Power	NF
34				
	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	04/15/2015	End of 2014/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 Power Markets LLC	PacifiCorp West	Sierra Pacific Power	SFP
2	Cargill Power Markets LLC	PacifiCorp West	PacifiCorp East	NF
3	Cargill Power Markets LLC	PacifiCorp West	NorthWestern/PacifiCorp East	NF
4	Cargill Power Markets LLC	PacifiCorp West	Bonneville Power Administration	NF
5	Cargill Power Markets LLC	PacifiCorp West	Sierra Pacific Power	NF
6	Cargill Power Markets LLC	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
7	Cargill Power Markets LLC	Bonneville Power Administration	PacifiCorp East	NF
8	Cargill Power Markets LLC	Bonneville Power Administration	Sierra Pacific Power	NF
9	Cargill Power Markets LLC	Avista	PacifiCorp East	NF
10	Cargill Power Markets LLC	Avista	PacifiCorp East	SFP
11	Cargill Power Markets LLC	Avista	Bonneville Power Administration	NF
12	Cargill Power Markets LLC	Avista	Sierra Pacific Power	NF
13	Cargill Power Markets LLC	Avista	Sierra Pacific Power	SFP
14	Cargill Power Markets LLC	Sierra Pacific Power	Bonneville Power Administration	NF
15	Cargill Power Markets LLC			AD
16	Constellation Energy			AD
17	Endure Energy			AD
18	Iberdrola Renewables LLC	PacifiCorp East	Sierra Pacific Power	NF
19	Iberdrola Renewables LLC	NorthWestern/PacifiCorp East	PacifiCorp East	NF
20	Iberdrola Renewables LLC	NorthWestern/PacifiCorp East	PacifiCorp East	NF
21	Iberdrola Renewables LLC	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
22	Iberdrola Renewables LLC	Idaho Power Company	PacifiCorp East	NF
23	Iberdrola Renewables LLC	Idaho Power Company	Sierra Pacific Power	NF
24	Iberdrola Renewables LLC	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
25	Iberdrola Renewables LLC	Bonneville Power Administration	PacifiCorp East	NF
26	Iberdrola Renewables LLC	Bonneville Power Administration	Sierra Pacific Power	NF
27	Iberdrola Renewables LLC	Avista	PacifiCorp East	NF
28	Iberdrola Renewables LLC	Avista	Sierra Pacific Power	NF
29	Iberdrola Renewables LLC	Sierra Pacific Power	Bonneville Power Administration	NF
30	Iberdrola Renewables LLC	Idaho Power Company	Bonneville Power Administration	NF
31	Iberdrola Renewables LLC			AD
32	MacQuarie Cook			AD
33	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
34				
	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	04/15/2015	End of 2014/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	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Idaho Power Company	NF
2	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
3	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
4	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	SFP
5	Morgan Stanley Capital Group Inc.	PacifiCorp East	NorthWestern/PacifiCorp East	NF
6	Morgan Stanley Capital Group Inc.	PacifiCorp East	Idaho Power Company	NF
7	Morgan Stanley Capital Group Inc.	PacifiCorp East	NorthWestern/PacifiCorp East	NF
8	Morgan Stanley Capital Group Inc.	PacifiCorp East	Bonneville Power Administration	NF
9	Morgan Stanley Capital Group Inc.	PacifiCorp East	Sierra Pacific Power	NF
10	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
11	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
12	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp West	NF
13	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Idaho Power Company	NF
14	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
15	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
16	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	SFP
17	Morgan Stanley Capital Group Inc.	PacifiCorp East	NorthWestern/PacifiCorp East	NF
18	Morgan Stanley Capital Group Inc.	PacifiCorp East	PacifiCorp East	NF
19	Morgan Stanley Capital Group Inc.	PacifiCorp East	NorthWestern/PacifiCorp East	NF
20	Morgan Stanley Capital Group Inc.	PacifiCorp East	Idaho Power Company	NF
21	Morgan Stanley Capital Group Inc.	PacifiCorp East	Bonneville Power Administration	NF
22	Morgan Stanley Capital Group Inc.	PacifiCorp East	Sierra Pacific Power	NF
23	Morgan Stanley Capital Group Inc.	PacifiCorp East	Sierra Pacific Power	SFP
24	Morgan Stanley Capital Group Inc.	PacifiCorp West	PacifiCorp East	NF
25	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Idaho Power Company	NF
26	Morgan Stanley Capital Group Inc.	Idaho Power Company	PacifiCorp East	NF
27	Morgan Stanley Capital Group Inc.	Idaho Power Company	PacifiCorp East	NF
28	Morgan Stanley Capital Group Inc.	Idaho Power Company	PacifiCorp West	NF
29	Morgan Stanley Capital Group Inc.	Idaho Power Company	Sierra Pacific Power	NF
30	Morgan Stanley Capital Group Inc.	PacifiCorp West	PacifiCorp East	NF
31	Morgan Stanley Capital Group Inc.	PacifiCorp West	Idaho Power Company	NF
32	Morgan Stanley Capital Group Inc.	PacifiCorp West	Bonneville Power Administration	NF
33	Morgan Stanley Capital Group Inc.	PacifiCorp West	Sierra Pacific Power	NF
34				
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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	Morgan Stanley Capital Group Inc.	Idaho Power Company	PacifiCorp East	NF
2	Morgan Stanley Capital Group Inc.	Idaho Power Company	Bonneville Power Administration	NF
3	Morgan Stanley Capital Group Inc.	Idaho Power Company	Sierra Pacific Power	NF
4	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
5	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
6	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp West	NF
7	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Idaho Power Company	NF
8	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
9	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
10	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	PacifiCorp East	NF
11	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	PacifiCorp East	NF
12	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	NorthWestern/PacifiCorp East	NF
13	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	Sierra Pacific Power	NF
14	Morgan Stanley Capital Group Inc.	Avista	PacifiCorp East	NF
15	Morgan Stanley Capital Group Inc.	Avista	PacifiCorp East	NF
16	Morgan Stanley Capital Group Inc.	Avista	NorthWestern/PacifiCorp East	NF
17	Morgan Stanley Capital Group Inc.	Avista	Bonneville Power Administration	NF
18	Morgan Stanley Capital Group Inc.	Avista	Sierra Pacific Power	NF
19	Morgan Stanley Capital Group Inc.	Avista	Sierra Pacific Power	SFP
20	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	PacifiCorp East	NF
21	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
22	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	PacifiCorp East	NF
23	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
24	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	Bonneville Power Administration	NF
25	Morgan Stanley Capital Group Inc.			AD
26	Nevada Power Company	PacifiCorp East	Sierra Pacific Power	NF
27	Nevada Power Company	PacifiCorp East	Sierra Pacific Power	NF
28	Nevada Power Company	PacifiCorp East	Sierra Pacific Power	SFP
29	Nevada Power Company	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
30	Nevada Power Company	Bonneville Power Administration	Sierra Pacific Power	NF
31	Nevada Power Company	Avista	Sierra Pacific Power	NF
32	Nevada Power Company	Avista	Sierra Pacific Power	SFP
33	Nevada Power Company	Sierra Pacific Power	PacifiCorp East	NF
34				
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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	Nevada Power Company	Sierra Pacific Power	Idaho Power Company	NF
2	Nevada Power Company	Sierra Pacific Power	Bonneville Power Administration	NF
3	Northwestern Energy			AD
4	PacifiCorp Inc.	PacifiCorp East	PacifiCorp West	NF
5	PacifiCorp Inc.	PacifiCorp East	Idaho Power Company	NF
6	PacifiCorp Inc.	PacifiCorp East	Idaho Power Company	LFP
7	PacifiCorp Inc.	PacifiCorp East	Bonneville Power Administration	NF
8	PacifiCorp Inc.	PacifiCorp East	PacifiCorp East	NF
9	PacifiCorp Inc.	PacifiCorp East	PacifiCorp East	SFP
10	PacifiCorp Inc.	PacifiCorp East	PacifiCorp West	NF
11	PacifiCorp Inc.	PacifiCorp East	Idaho Power Company	NF
12	PacifiCorp Inc.	PacifiCorp East	Bonneville Power Administration	NF
13	PacifiCorp Inc.	PacifiCorp West	PacifiCorp East	NF
14	PacifiCorp Inc.	PacifiCorp West	PacifiCorp East	SFP
15	PacifiCorp Inc.	PacifiCorp West	Bonneville Power Administration	NF
16	PacifiCorp Inc.	Idaho Power Company	Sierra Pacific Power	SFP
17	PacifiCorp Inc.	Idaho Power Company	PacifiCorp East	NF
18	PacifiCorp Inc.	Idaho Power Company	PacifiCorp East	NF
19	PacifiCorp Inc.	Idaho Power Company	PacifiCorp East	NF
20	PacifiCorp Inc.	Idaho Power Company	PacifiCorp East	LFP
21	PacifiCorp Inc.	Idaho Power Company	NorthWestern/PacifiCorp East	NF
22	PacifiCorp Inc.	Idaho Power Company	Idaho Power Company	LFP
23	PacifiCorp Inc.	Idaho Power Company	Idaho Power Company	NF
24	PacifiCorp Inc.	Idaho Power Company	Bonneville Power Administration	NF
25	PacifiCorp Inc.	Idaho Power Company	Avista	NF
26	PacifiCorp Inc.	Bonneville Power Administration	PacifiCorp East	NF
27	PacifiCorp Inc.	Avista	PacifiCorp East	NF
28	PacifiCorp Inc.	Avista	PacifiCorp West	NF
29	PacifiCorp Inc.	Avista	Bonneville Power Administration	NF
30	PacifiCorp Inc.			AD
31	Portland General Electric Company	PacifiCorp East	NorthWestern/PacifiCorp East	NF
32	Portland General Electric Company	PacifiCorp East	Bonneville Power Administration	NF
33	Portland General Electric Company	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
34				
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/Q4

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

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

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/Q4

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

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
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Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Powerex Corporation			AD
2	PPL EnergyPlus, LLC	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
3	PPL EnergyPlus, LLC	PacifiCorp East	Bonneville Power Administration	NF
4	PPL EnergyPlus, LLC	PacifiCorp East	Sierra Pacific Power	NF
5	PPL EnergyPlus, LLC	NorthWestern/PacifiCorp East	PacifiCorp East	NF
6	PPL EnergyPlus, LLC	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
7	PPL EnergyPlus, LLC	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
8	PPL EnergyPlus, LLC			AD
9	Puget Sound Energy, Inc.	Idaho Power Company	NorthWestern/PacifiCorp East	NF
10	Puget Sound Energy, Inc.	PacifiCorp West	Bonneville Power Administration	NF
11	Puget Sound Energy, Inc.	PacifiCorp West	Avista	NF
12	Puget Sound Energy, Inc.	Avista	Bonneville Power Administration	NF
13	Puget Sound Energy, Inc.			AD
14	Rainbow Energy Marketing Corporation	PacifiCorp East	NorthWestern/PacifiCorp East	NF
15	Rainbow Energy Marketing Corporation	PacifiCorp East	NorthWestern/PacifiCorp East	NF
16	Rainbow Energy Marketing Corporation	PacifiCorp East	NorthWestern/PacifiCorp East	SFP
17	Rainbow Energy Marketing Corporation	PacifiCorp East	NorthWestern/PacifiCorp East	NF
18	Rainbow Energy Marketing Corporation	PacifiCorp East	NorthWestern/PacifiCorp East	NF
19	Rainbow Energy Marketing Corporation	PacifiCorp East	NorthWestern/PacifiCorp East	SFP
20	Rainbow Energy Marketing Corporation	PacifiCorp West	PacifiCorp East	NF
21	Rainbow Energy Marketing Corporation	Avista	PacifiCorp East	NF
22	Rainbow Energy Marketing Corporation	Avista	PacifiCorp East	SFP
23	Rainbow Energy Marketing Corporation			AD
24	Seattle City Light			AD
25	Sempra Energy			AD
26	Shell Energy North America (US), L.P.	PacifiCorp East	Bonneville Power Administration	NF
27	Shell Energy North America (US), L.P.	PacifiCorp East	Sierra Pacific Power	NF
28	Shell Energy North America (US), L.P.	PacifiCorp East	Sierra Pacific Power	SFP
29	Shell Energy North America (US), L.P.	PacifiCorp East	Bonneville Power Administration	NF
30	Shell Energy North America (US), L.P.	PacifiCorp East	Sierra Pacific Power	NF
31	Shell Energy North America (US), L.P.	PacifiCorp East	Sierra Pacific Power	SFP
32	Shell Energy North America (US), L.P.	Idaho Power Company	PacifiCorp East	NF
33	Shell Energy North America (US), L.P.	Idaho Power Company	PacifiCorp East	NF
34				
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
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Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Shell Energy North America (US), L.P.	Idaho Power Company	Sierra Pacific Power	NF
2	Shell Energy North America (US), L.P.	Idaho Power Company	Sierra Pacific Power	SFP
3	Shell Energy North America (US), L.P.	Idaho Power Company	Bonneville Power Administration	NF
4	Shell Energy North America (US), L.P.	Idaho Power Company	Sierra Pacific Power	SFP
5	Shell Energy North America (US), L.P.	PacifiCorp West	Bonneville Power Administration	NF
6	Shell Energy North America (US), L.P.	PacifiCorp West	Sierra Pacific Power	SFP
7	Shell Energy North America (US), L.P.	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
8	Shell Energy North America (US), L.P.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
9	Shell Energy North America (US), L.P.	Bonneville Power Administration	PacifiCorp East	NF
10	Shell Energy North America (US), L.P.	Bonneville Power Administration	Sierra Pacific Power	NF
11	Shell Energy North America (US), L.P.	Avista	PacifiCorp East	NF
12	Shell Energy North America (US), L.P.	Avista	Sierra Pacific Power	NF
13	Shell Energy North America (US), L.P.	Avista	Sierra Pacific Power	SFP
14	Shell Energy North America (US), L.P.	Sierra Pacific Power	PacifiCorp East	NF
15	Shell Energy North America (US), L.P.	Sierra Pacific Power	PacifiCorp East	SFP
16	Shell Energy North America (US), L.P.	Sierra Pacific Power	PacifiCorp East	NF
17	Shell Energy North America (US), L.P.	Sierra Pacific Power	Bonneville Power Administration	NF
18	Shell Energy North America (US), L.P.	Sierra Pacific Power	Bonneville Power Administration	SFP
19	Shell Energy North America (US), L.P.	Sierra Pacific Power	Bonneville Power Administration	LFP
20	Shell Energy North America (US), L.P.	Sierra Pacific Power	Avista	NF
21	Shell Energy North America (US), L.P.	Sierra Pacific Power	Sierra Pacific Power	NF
22	Shell Energy North America (US), L.P.	Sierra Pacific Power	Sierra Pacific Power	SFP
23	Shell Energy North America (US), L.P.	Sierra Pacific Power	PacifiCorp East	NF
24	Shell Energy North America (US), L.P.	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
25	Shell Energy North America (US), L.P.	Sierra Pacific Power	Bonneville Power Administration	NF
26	Shell Energy North America (US), L.P.	Idaho Power Company	PacifiCorp East	NF
27	Shell Energy North America (US), L.P.	Idaho Power Company	PacifiCorp East	SFP
28	Shell Energy North America (US), L.P.	Idaho Power Company	Bonneville Power Administration	NF
29	Shell Energy North America (US), L.P.	Idaho Power Company	Bonneville Power Administration	SFP
30	Shell Energy North America (US), L.P.			AD
31	Sierra Pacific Power Co.	PacifiCorp East	Sierra Pacific Power	NF
32	Sierra Pacific Power Co.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
33	Sierra Pacific Power Co.	PacifiCorp East	Sierra Pacific Power	NF
34				
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/Q4

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Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Sierra Pacific Power Co.	Idaho Power Company	Sierra Pacific Power	NF
2	Sierra Pacific Power Co.	Avista	Sierra Pacific Power	NF
3	Sierra Pacific Power Co.	Sierra Pacific Power	PacifiCorp East	NF
4	Sierra Pacific Power Co.	Sierra Pacific Power	Bonneville Power Administration	NF
5	Sierra Pacific Power Co.			AD
6	Southern California Edison	PacifiCorp East	Sierra Pacific Power	NF
7	Southern California Edison	Bonneville Power Administration	PacifiCorp East	NF
8	Southern California Edison			AD
9	Tenaska Power Services Co.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
10	Tenaska Power Services Co.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
11	Tenaska Power Services Co.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
12	Tenaska Power Services Co.	PacifiCorp East	Bonneville Power Administration	NF
13	Tenaska Power Services Co.	PacifiCorp West	PacifiCorp East	NF
14	Tenaska Power Services Co.	PacifiCorp West	PacifiCorp East	SFP
15	Tenaska Power Services Co.	Bonneville Power Administration	PacifiCorp East	NF
16	Tenaska Power Services Co.	Bonneville Power Administration	PacifiCorp East	NF
17	Tenaska Power Services Co.	Bonneville Power Administration	Sierra Pacific Power	NF
18	Tenaska Power Services Co.	Avista	PacifiCorp East	NF
19	Tenaska Power Services Co.	Avista	Sierra Pacific Power	NF
20	Tenaska Power Services Co.			AD
21	The Energy Authority, Inc.	PacifiCorp East	Bonneville Power Administration	NF
22	The Energy Authority, Inc.	Bonneville Power Administration	PacifiCorp East	NF
23	The Energy Authority, Inc.	Bonneville Power Administration	PacifiCorp East	NF
24	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp East	NorthWestern/PacifiCorp East	NF
25	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp East	Idaho Power Company	NF
26	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp East	Bonneville Power Administration	NF
27	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp East	Sierra Pacific Power	NF
28	Transalta Energy Marketing (U.S.) Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
29	Transalta Energy Marketing (U.S.) Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
30	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp East	NorthWestern/PacifiCorp East	NF
31	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp East	Bonneville Power Administration	NF
32	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp East	Sierra Pacific Power	NF
33	Transalta Energy Marketing (U.S.) Inc.	Idaho Power Company	PacifiCorp East	NF
34				
	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	04/15/2015	End of 2014/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	Transalta Energy Marketing (U.S.) Inc.	Idaho Power Company	Sierra Pacific Power	NF
2	Transalta Energy Marketing (U.S.) Inc.	Bonneville Power Administration	PacifiCorp East	NF
3	Transalta Energy Marketing (U.S.) Inc.	Bonneville Power Administration	Sierra Pacific Power	NF
4	Transalta Energy Marketing (U.S.) Inc.	Sierra Pacific Power	Idaho Power Company	NF
5	Transalta Energy Marketing (U.S.) Inc.	Sierra Pacific Power	Bonneville Power Administration	NF
6	Transalta Energy Marketing (U.S.) Inc.			AD
7	United Materials of Great Falls	NorthWestern/PacifiCorp East	Idaho Power Company	NF
8	Utah Associated Municipal Power	PacifiCorp East	Sierra Pacific Power	NF
9	Utah Associated Municipal Power	Sierra Pacific Power	PacifiCorp East	NF
10	Utah Associated Municipal Power			AD
11				
12				
13				
14				
15				
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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)	
9				333,238	333,238	1
9						2
9				267,961	267,961	3
9						4
9				1,236,894	1,236,894	5
9						6
9						7
Legacy	Minidoka, Idaho	Various in Idaho		8,846	8,846	8
4				308,061	308,061	9
9				2,049	2,049	10
9						11
Legacy	LaGrande, Oregon	Various in Idaho		16,782	16,782	12
5/6	JEFF	IPCO		15,555	15,555	13
5/6	BRDY	IPCO		3,764	3,764	14
8	JEFF	LOLO		798	798	15
8						16
8	BPAT.NWMT	BRDY		25	25	17
8						18
8	BPAT.NWMT	M345		1,719	1,719	19
8	LAGRANDE	LAGRANDE		1,079	1,079	20
8	LAGRANDE	M345		34,394	34,394	21
8	LOLO	LAGRANDE		322	322	22
8	LOLO	M345		5,429	5,429	23
8						24
8	AVAT.NWMT	M345		46	46	25
8	BORA	BPAT.NWMT		818	818	26
8	BORA	LAGRANDE		4,923	4,923	27
8	BPAT.NWMT	LAGRANDE		775	775	28
8	BPAT.NWMT	M345		944	944	29
8	BRDY	M345		396	396	30
8	ENPR	BORA		740	740	31
7	ENPR	BORA		1,269	1,269	32
8	ENPR	M345		916	916	33
						34
			0	**6,721,533**	**6,721,533**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Line No.
7	ENPR	M345		320	320	1
8	JBSN	BORA		467	467	2
8	JBSN	BPAT.NWMT		20	20	3
8	JBSN	LAGRANDE		735	735	4
8	JBSN	M345		160	160	5
8	JEFF	M345		254	254	6
8	LAGRANDE	BORA		468	468	7
8	LAGRANDE	M345		667	667	8
8	LOLO	BORA		984	984	9
7	LOLO	BORA		1,318	1,318	10
8	LOLO	LAGRANDE		25	25	11
8	LOLO	M345		66,652	66,652	12
7	LOLO	M345		5,416	5,416	13
8	M345	LAGRANDE		1,400	1,400	14
8						15
8						16
8						17
8	BORA	M345		62	62	18
8	BPAT.NWMT	BORA		120	120	19
8	BPAT.NWMT	BRDY		49	49	20
8	BPAT.NWMT	M345		1,969	1,969	21
8	HMWY	BORA		3,541	3,541	22
8	HMWY	M345		2,714	2,714	23
8	JEFF	M345		100	100	24
8	LAGRANDE	BORA		4,321	4,321	25
8	LAGRANDE	M345		25,422	25,422	26
8	LOLO	BORA		412	412	27
8	LOLO	M345		263	263	28
8	M345	LAGRANDE		1,834	1,834	29
8	OBBLPR	LAGRANDE		20	20	30
8						31
8						32
8	AVAT.NWMT	BRDY		417	417	33
						34
			0	**6,721,533**	**6,721,533**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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.
8	AVAT.NWMT	HMWY		87	87	1
8	AVAT.NWMT	LAGRANDE		51	51	2
8	AVAT.NWMT	M345		22,002	22,002	3
7	AVAT.NWMT	M345		47,695	47,695	4
8	BORA	BPAT.NWMT		281	281	5
8	BORA	HMWY		45	45	6
8	BORA	JEFF		25	25	7
8	BORA	LAGRANDE		426	426	8
8	BORA	M345		7,224	7,224	9
8	BPAT.NWMT	BORA		638	638	10
8	BPAT.NWMT	BRDY		96	96	11
8	BPAT.NWMT	ENPR		360	360	12
8	BPAT.NWMT	HMWY		75	75	13
8	BPAT.NWMT	LAGRANDE		18,742	18,742	14
8	BPAT.NWMT	M345		11,972	11,972	15
7	BPAT.NWMT	M345		3,262	3,262	16
8	BRDY	AVAT.NWMT		82	82	17
8	BRDY	BORA		2	2	18
8	BRDY	BPAT.NWMT		118	118	19
8	BRDY	HMWY		392	392	20
8	BRDY	LAGRANDE		12,636	12,636	21
8	BRDY	M345		35,780	35,780	22
7	BRDY	M345		510	510	23
8	ENPR	BRDY		30	30	24
8	GSHN	HMWY		96	96	25
8	HMWY	BORA		12,608	12,608	26
8	HMWY	BRDY		1,638	1,638	27
8	HMWY	JBSN		942	942	28
8	HMWY	M345		3,679	3,679	29
8	JBSN	BORA		1,975	1,975	30
8	JBSN	HMWY		25	25	31
8	JBSN	LAGRANDE		250	250	32
8	JBSN	M345		298	298	33
						34
			0	**6,721,533**	**6,721,533**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
8	JBWT	BORA		14	14	1
8	JBWT	LAGRANDE		1,930	1,930	2
8	JBWT	M345		1,530	1,530	3
8	JEFF	BORA		2,581	2,581	4
8	JEFF	BRDY		128	128	5
8	JEFF	ENPR		258	258	6
8	JEFF	HMWY		13	13	7
8	JEFF	LAGRANDE		10,801	10,801	8
8	JEFF	M345		139,494	139,494	9
8	LAGRANDE	BORA		6,060	6,060	10
8	LAGRANDE	BRDY		2,870	2,870	11
8	LAGRANDE	JEFF		35	35	12
8	LAGRANDE	M345		22,679	22,679	13
8	LOLO	BORA		4,118	4,118	14
8	LOLO	BRDY		14	14	15
8	LOLO	JEFF		80	80	16
8	LOLO	LAGRANDE		25	25	17
8	LOLO	M345		10,415	10,415	18
7	LOLO	M345		3,572	3,572	19
8	M345	BORA		2,078	2,078	20
8	M345	BPAT.NWMT		759	759	21
8	M345	BRDY		313	313	22
8	M345	JEFF		135	135	23
8	M345	LAGRANDE		1,198	1,198	24
8						25
8	BORA	M345		594	594	26
8	BRDY	M345		7,371	7,371	27
7	BRDY	M345		4,984	4,984	28
8	JEFF	M345		4,471	4,471	29
8	LAGRANDE	M345		2,531	2,531	30
8	LOLO	M345		673	673	31
7	LOLO	M345		800	800	32
8	M345	BRDY		260	260	33
						34
			0	**6,721,533**	**6,721,533**	

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	04/15/2015	End of 2014/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		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
8	M345	HMWY		790	790	1
8	M345	LAGRANDE		1,360	1,360	2
8						3
8	BORA	ENPR		1,684	1,684	4
8	BORA	HMWY		444	444	5
7	BORA	KPRT		1,340,222	1,340,222	6
8	BORA	LAGRANDE		2,195	2,195	7
8	BRDY	BRDY		1,096	1,096	8
7	BRDY	BRDY		76	76	9
8	BRDY	ENPR		300	300	10
8	BRDY	KPRT		5,243	5,243	11
8	BRDY	LAGRANDE		500	500	12
8	ENPR	BORA		211,505	211,505	13
7	ENPR	BORA		117,399	117,399	14
8	ENPR	LAGRANDE		264	264	15
7	HMWY	M345		3,676	3,676	16
8	IPCOGEN	BORA		50	50	17
8	JBWT	BORA		1,614	1,614	18
8	JBWT	BRDY		19	19	19
7	JBWT	BRDY		162,792	162,792	20
8	JBWT	GSHN		36,135	36,135	21
7	JBWT	HMWY		644,162	644,162	22
8	JBWT	KPRT		3,673	3,673	23
8	JBWT	LAGRANDE		31,250	31,250	24
8	JBWT	LOLO		123	123	25
8	LAGRANDE	BORA		292	292	26
8	LOLO	BORA		1,098	1,098	27
8	LOLO	ENPR		3,896	3,896	28
8	LOLO	LAGRANDE		3	3	29
8						30
8	BORA	BPAT.NWMT		681	681	31
8	BORA	LAGRANDE		75	75	32
8	BPAT.NWMT	LAGRANDE		15	15	33
						34
			0	**6,721,533**	**6,721,533**	

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	04/15/2015	End of 2014/Q4

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Line No.
8	BPAT.NWMT	M345		501	501	1
8	BRDY	LAGRANDE		13,476	13,476	2
8	HMWY	BORA		3,837	3,837	3
8	HMWY	M345		1,092	1,092	4
8	JEFF	LAGRANDE		5,919	5,919	5
8	LAGRANDE	M345		6,238	6,238	6
8	M345	LAGRANDE		719	719	7
8						8
8	BORA	BPAT.NWMT		476	476	9
8	BORA	BRDY		4	4	10
8	BORA	ENPR		32	32	11
8	BORA	HMWY		1,853	1,853	12
8	BORA	JEFF		14	14	13
8	BORA	LAGRANDE		11,765	11,765	14
8	BORA	M345		121	121	15
8	BPAT.NWMT	BORA		633	633	16
7	BPAT.NWMT	BORA		66,625	66,625	17
8	BPAT.NWMT	BRDY		157	157	18
8	BPAT.NWMT	HMWY		5	5	19
8	BPAT.NWMT	LAGRANDE		397	397	20
8	BPAT.NWMT	M345		3,564	3,564	21
8	BRDY	BPAT.NWMT		520	520	22
8	BRDY	ENPR		95	95	23
8	BRDY	HMWY		1,148	1,148	24
8	BRDY	LAGRANDE		7,809	7,809	25
8	BRDY	M345		3,974	3,974	26
8	ENPR	BORA		108,510	108,510	27
7	ENPR	BORA		87,870	87,870	28
8	ENPR	BRDY		868	868	29
8	ENPR	M345		2,887	2,887	30
8	GSHN	BPAT.NWMT		210	210	31
8	GSHN	BRDY		2	2	32
8	GSHN	HMWY		560	560	33
						34
			0	**6,721,533**	**6,721,533**	

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.
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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)	
8	GSHN	JEFF		45	45	1
8	GSHN	LAGRANDE		2,927	2,927	2
8	GSHN	M345		9	9	3
8	HMWY	BORA		81,942	81,942	4
7	HMWY	BORA		22,273	22,273	5
8	HMWY	BRDY		5,275	5,275	6
8	HMWY	JBSN		50	50	7
8	HMWY	M345		35,568	35,568	8
7	HMWY	M345		4,810	4,810	9
8	JBSN	BPAT.NWMT		27	27	10
8	JBSN	JEFF		40	40	11
8	JBSN	LAGRANDE		925	925	12
8	JBSN	M345		47	47	13
8	JBWT	ENPR		40	40	14
8	JBWT	HMWY		330	330	15
8	JBWT	LAGRANDE		2,388	2,388	16
7	JEFF	BORA		624	624	17
8	JEFF	BRDY		46	46	18
8	JEFF	HMWY		445	445	19
8	JEFF	LAGRANDE		905	905	20
8	JEFF	M345		15	15	21
8	LAGRANDE	BORA		11,348	11,348	22
7	LAGRANDE	BORA		2,347	2,347	23
8	LAGRANDE	BRDY		6,767	6,767	24
8	LAGRANDE	JBSN		355	355	25
8	LAGRANDE	M345		77,404	77,404	26
7	LAGRANDE	M345		7,666	7,666	27
8	LOLO	BORA		170	170	28
8	LOLO	M345		528	528	29
8	M345	BPAT.NWMT		8	8	30
8	M345	HMWY		193	193	31
8	M345	JEFF		3	3	32
8	M345	LAGRANDE		542	542	33
						34
			0	**6,721,533**	**6,721,533**	

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)	
8						1
8	BPAT.NWMT	LAGRANDE		8,009	8,009	2
8	BRDY	LAGRANDE		12,328	12,328	3
8	BRDY	M345		263	263	4
8	JEFF	BORA		987	987	5
8	JEFF	LAGRANDE		10,932	10,932	6
8	JEFF	M345		175	175	7
8						8
8	HMWY	AVAT.NWMT		8	8	9
8	JBSN	LAGRANDE		1,296	1,296	10
8	JBSN	LOLO		672	672	11
8	LOLO	LAGRANDE		1,358	1,358	12
8						13
8	BORA	BPAT.NWMT		432	432	14
8	BORA	JEFF		200	200	15
7	BORA	JEFF		1,968	1,968	16
8	BRDY	AVAT.NWMT		72	72	17
8	BRDY	JEFF		150	150	18
7	BRDY	JEFF		727	727	19
8	JBSN	BRDY		200	200	20
8	LOLO	BORA		2,063	2,063	21
7	LOLO	BORA		1,380	1,380	22
8						23
8						24
8						25
8	BORA	LAGRANDE		1,065	1,065	26
8	BORA	M345		336	336	27
7	BORA	M345		756	756	28
8	BRDY	LAGRANDE		22,052	22,052	29
8	BRDY	M345		26,201	26,201	30
7	BRDY	M345		23,580	23,580	31
8	HMWY	BORA		407	407	32
8	HMWY	BRDY		1,790	1,790	33
						34
			0	**6,721,533**	**6,721,533**	

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	04/15/2015	End of 2014/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.
8	HMWY	M345		45,891	45,891	1
7	HMWY	M345		6,787	6,787	2
8	IPCOGEN	LAGRANDE		845	845	3
7	IPCOGEN	LAGRANDE		80	80	4
8	JBSN	LAGRANDE		8	8	5
7	JBSN	M345		2,200	2,200	6
8	JEFF	LAGRANDE		2,019	2,019	7
8	JEFF	M345		1,154	1,154	8
8	LAGRANDE	BRDY		7,743	7,743	9
8	LAGRANDE	M345		87,127	87,127	10
8	LOLO	BORA		23	23	11
8	LOLO	M345		68,925	68,925	12
7	LOLO	M345		25,524	25,524	13
8	LYPK	BORA		8,486	8,486	14
7	LYPK	BORA		2,469	2,469	15
8	LYPK	BRDY		1,339	1,339	16
8	LYPK	LAGRANDE		16,513	16,513	17
7	LYPK	LAGRANDE		96	96	18
7	LYPK	LAGRANDE		36,582	36,582	19
8	LYPK	LOLO		18	18	20
8	LYPK	M345		43,517	43,517	21
7	LYPK	M345		198,617	198,617	22
8	M345	BRDY		150	150	23
8	M345	JEFF		8	8	24
8	M345	LAGRANDE		1,655	1,655	25
8	MDSK	BORA		256	256	26
7	MDSK	BORA		3,672	3,672	27
8	MDSK	LAGRANDE		1,485	1,485	28
7	OBBLPR	LAGRANDE		400	400	29
8						30
8	BORA	M345		130	130	31
8	BPAT.NWMT	M345		556	556	32
8	BRDY	M345		50	50	33
						34
			0	**6,721,533**	**6,721,533**	

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	Line No.
8	HMWY	M345		280	280	1
8	LOLO	M345		200	200	2
8	M345	BORA		1,311	1,311	3
8	M345	LAGRANDE		361	361	4
8						5
8	BORA	M345		227	227	6
8	LAGRANDE	BORA		605	605	7
8						8
8	BPAT.NWMT	BORA		308	308	9
8	BPAT.NWMT	BRDY		846	846	10
8	BPAT.NWMT	M345		128	128	11
8	BRDY	LAGRANDE		941	941	12
8	JBSN	BRDY		342	342	13
7	JBSN	BRDY		4,736	4,736	14
8	LAGRANDE	BORA		600	600	15
8	LAGRANDE	BRDY		5	5	16
8	LAGRANDE	M345		22	22	17
8	LOLO	BORA		342	342	18
8	LOLO	M345		600	600	19
8						20
8	BRDY	LAGRANDE		90	90	21
8	LAGRANDE	BORA		563	563	22
8	LAGRANDE	BRDY		2,793	2,793	23
8	BORA	BPAT.NWMT		11	11	24
8	BORA	HMWY		429	429	25
8	BORA	LAGRANDE		3,504	3,504	26
8	BORA	M345		80	80	27
8	BPAT.NWMT	BORA		66	66	28
8	BPAT.NWMT	M345		29	29	29
8	BRDY	BPAT.NWMT		160	160	30
8	BRDY	LAGRANDE		300	300	31
8	BRDY	M345		20	20	32
8	HMWY	BORA		39,138	39,138	33
						34
			0	**6,721,533**	**6,721,533**	

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	04/15/2015	End of 2014/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		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
8	HMWY	M345		1,802	1,802	1
8	LAGRANDE	BORA		6,049	6,049	2
8	LAGRANDE	M345		4,592	4,592	3
8	M345	HMWY		50	50	4
8	M345	LAGRANDE		121	121	5
8						6
8	AVAT.NWMT	IPCO		1	1	7
8	BORA	M345		10,848	10,848	8
8	M345	BORA		27	27	9
8						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
			0	**6,721,533**	**6,721,533**	

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.
1,270,731	26,987		1,297,718	1
-20,161			-20,161	2
1,309,561	-143,134		1,166,427	3
-9,420			-9,420	4
4,630,939	56,170		4,687,109	5
-45,830			-45,830	6
-8,758			-8,758	7
	14,330		14,330	8
	184,783		184,783	9
8,018	1,307		9,325	10
-114			-114	11
54,702			54,702	12
	18,455		18,455	13
	4,466		4,466	14
	2,080		2,080	15
	-69		-69	16
	117		117	17
	-51		-51	18
	6,616		6,616	19
	4,153		4,153	20
	132,383		132,383	21
	1,239		1,239	22
	20,896		20,896	23
	-989		-989	24
	143		143	25
	2,537		2,537	26
	15,268		15,268	27
	2,404		2,404	28
	2,928		2,928	29
	1,228		1,228	30
	2,295		2,295	31
	3,936		3,936	32
	2,841		2,841	33
				34
7,189,668	**15,438,248**	**0**	**22,627,916**	

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.
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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.
	992		992	1
	1,448		1,448	2
	62		62	3
	2,280		2,280	4
	496		496	5
	788		788	6
	1,451		1,451	7
	2,069		2,069	8
	3,052		3,052	9
	4,088		4,088	10
	78		78	11
	206,715		206,715	12
	16,797		16,797	13
	4,342		4,342	14
	-18,793		-18,793	15
	-349		-349	16
	-20		-20	17
	259		259	18
	502		502	19
	205		205	20
	8,237		8,237	21
	14,813		14,813	22
	11,353		11,353	23
	418		418	24
	18,076		18,076	25
	106,346		106,346	26
	1,724		1,724	27
	1,100		1,100	28
	7,672		7,672	29
	84		84	30
	-395		-395	31
	-10		-10	32
	1,617		1,617	33
				34
7,189,668	**15,438,248**	**0**	**22,627,916**	

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.
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REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	337		337	1
	198		198	2
	85,333		85,333	3
	184,982		184,982	4
	1,090		1,090	5
	175		175	6
	97		97	7
	1,652		1,652	8
	28,018		28,018	9
	2,474		2,474	10
	372		372	11
	1,396		1,396	12
	291		291	13
	72,690		72,690	14
	46,433		46,433	15
	12,651		12,651	16
	318		318	17
	8		8	18
	458		458	19
	1,520		1,520	20
	49,008		49,008	21
	138,770		138,770	22
	1,978		1,978	23
	116		116	24
	372		372	25
	48,899		48,899	26
	6,353		6,353	27
	3,653		3,653	28
	14,269		14,269	29
	7,660		7,660	30
	97		97	31
	970		970	32
	1,156		1,156	33
				34
7,189,668	**15,438,248**	**0**	**22,627,916**	

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.
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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.
	54		54	1
	7,485		7,485	2
	5,934		5,934	3
	10,010		10,010	4
	496		496	5
	1,001		1,001	6
	50		50	7
	41,891		41,891	8
	541,018		541,018	9
	23,503		23,503	10
	11,131		11,131	11
	136		136	12
	87,959		87,959	13
	15,971		15,971	14
	54		54	15
	310		310	16
	97		97	17
	40,394		40,394	18
	13,854		13,854	19
	8,059		8,059	20
	2,944		2,944	21
	1,214		1,214	22
	524		524	23
	4,646		4,646	24
	-5,250		-5,250	25
	2,419		2,419	26
	30,019		30,019	27
	20,298		20,298	28
	18,208		18,208	29
	10,308		10,308	30
	2,741		2,741	31
	3,258		3,258	32
	1,059		1,059	33
				34
7,189,668	**15,438,248**	**0**	**22,627,916**	

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.
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REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	3,217		3,217	1
	5,539		5,539	2
	-28		-28	3
	10,055		10,055	4
	2,651		2,651	5
				6
	13,106		13,106	7
	6,544		6,544	8
	454		454	9
	1,791		1,791	10
	31,305		31,305	11
	2,985		2,985	12
	1,262,864		1,262,864	13
	700,972		700,972	14
	1,576		1,576	15
	21,949		21,949	16
	299		299	17
	9,637		9,637	18
	113		113	19
	972,006		972,006	20
	215,757		215,757	21
	3,846,194		3,846,194	22
	21,931		21,931	23
	186,589		186,589	24
	734		734	25
	1,744		1,744	26
	6,556		6,556	27
	23,262		23,262	28
	18		18	29
	-106,595		-106,595	30
	3,035		3,035	31
	334		334	32
	67		67	33
				34
7,189,668	**15,438,248**	**0**	**22,627,916**	

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.
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REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	2,232		2,232	1
	60,049		60,049	2
	17,098		17,098	3
	4,866		4,866	4
	26,375		26,375	5
	27,797		27,797	6
	3,204		3,204	7
	-145		-145	8
	2,036		2,036	9
	17		17	10
	137		137	11
	7,926		7,926	12
	60		60	13
	50,321		50,321	14
	518		518	15
	2,707		2,707	16
	284,966		284,966	17
	672		672	18
	21		21	19
	1,698		1,698	20
	15,244		15,244	21
	2,224		2,224	22
	406		406	23
	4,910		4,910	24
	33,400		33,400	25
	16,997		16,997	26
	464,115		464,115	27
	375,835		375,835	28
	3,713		3,713	29
	12,348		12,348	30
	898		898	31
	9		9	32
	2,395		2,395	33
				34
7,189,668	**15,438,248**	**0**	**22,627,916**	

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.
	192		192	1
	12,519		12,519	2
	38		38	3
	350,480		350,480	4
	95,265		95,265	5
	22,562		22,562	6
	214		214	7
	152,130		152,130	8
	20,573		20,573	9
	115		115	10
	171		171	11
	3,956		3,956	12
	201		201	13
	171		171	14
	1,411		1,411	15
	10,214		10,214	16
	2,669		2,669	17
	197		197	18
	1,903		1,903	19
	3,871		3,871	20
	64		64	21
	48,537		48,537	22
	10,039		10,039	23
	28,944		28,944	24
	1,518		1,518	25
	331,070		331,070	26
	32,789		32,789	27
	727		727	28
	2,258		2,258	29
	34		34	30
	825		825	31
	13		13	32
	2,318		2,318	33
				34
7,189,668	**15,438,248**	**0**	**22,627,916**	

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.
	-34,259		-34,259	1
	34,098		34,098	2
	52,486		52,486	3
	1,120		1,120	4
	4,202		4,202	5
	46,542		46,542	6
	745		745	7
	-1,188		-1,188	8
	25		25	9
	4,055		4,055	10
	2,103		2,103	11
	4,249		4,249	12
	-720		-720	13
	1,522		1,522	14
	705		705	15
	6,934		6,934	16
	254		254	17
	528		528	18
	2,561		2,561	19
	705		705	20
	7,268		7,268	21
	4,862		4,862	22
	-2,844		-2,844	23
	-23,282		-23,282	24
	-1,145		-1,145	25
	4,717		4,717	26
	1,488		1,488	27
	3,349		3,349	28
	97,680		97,680	29
	116,058		116,058	30
	104,448		104,448	31
	1,803		1,803	32
	7,929		7,929	33
				34
7,189,668	**15,438,248**	**0**	**22,627,916**	

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.
	203,275		203,275	1
	30,063		30,063	2
	3,743		3,743	3
	354		354	4
	35		35	5
	9,745		9,745	6
	8,943		8,943	7
	5,112		5,112	8
	34,298		34,298	9
	385,931		385,931	10
	102		102	11
	305,305		305,305	12
	113,059		113,059	13
	37,589		37,589	14
	10,936		10,936	15
	5,931		5,931	16
	73,145		73,145	17
	425		425	18
	162,041		162,041	19
	80		80	20
	192,760		192,760	21
	879,779		879,779	22
	664		664	23
	35		35	24
	7,331		7,331	25
	1,134		1,134	26
	16,265		16,265	27
	6,578		6,578	28
	1,772		1,772	29
	-1,783		-1,783	30
	557		557	31
	2,381		2,381	32
	214		214	33
				34
7,189,668	**15,438,248**	**0**	**22,627,916**	

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	04/15/2015	End of 2014/Q4

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

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	1,199		1,199	1
	856		856	2
	5,613		5,613	3
	1,546		1,546	4
	-14,169		-14,169	5
	1,125		1,125	6
	2,999		2,999	7
	-4		-4	8
	1,000		1,000	9
	2,747		2,747	10
	416		416	11
	3,056		3,056	12
	1,111		1,111	13
	15,380		15,380	14
	1,948		1,948	15
	16		16	16
	71		71	17
	1,111		1,111	18
	1,948		1,948	19
	-96		-96	20
	381		381	21
	2,382		2,382	22
	11,818		11,818	23
	43		43	24
	1,696		1,696	25
	13,854		13,854	26
	316		316	27
	261		261	28
	115		115	29
	633		633	30
	1,186		1,186	31
	79		79	32
	154,739		154,739	33
				34
7,189,668	**15,438,248**	**0**	**22,627,916**	

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.
	7,125		7,125	1
	23,916		23,916	2
	18,155		18,155	3
	198		198	4
	478		478	5
	-419		-419	6
	5		5	7
	40,577		40,577	8
	101		101	9
	-164		-164	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
7,189,668	**15,438,248**	**0**	**22,627,916**	

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 servics is the customers demand at the time of Idaho Power Company transmission system peak and varies by month.

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

Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.

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

The network service agreement between Idaho Power and the Bonneville Power Administration for the USBR expired December 31,2014 and was subsequently renewed, with a new expiration date of 12/31/23. The billing demand for network service is the customers demand at the time of Idaho Power Company transmission system peak and varies by month.

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

Open Access Transmission tariff, Schedule 9 Network Integration Transmission Service.

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

Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.

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

The network service agreement between Idaho Power and the Bonneville Power Administration for the Priority Firm Customers 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.: 6 Column: h

Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.

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

Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.

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 contract between Idaho Power and the Milner Irrigation District expires December 31, 2017.

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

4, Open Access Transmission Tariff, Schedule 4 Energy Imbalance Service.

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

The agreement between Idaho Power and the City of Seattle expires December 31,2017. City of Seattle has re-sold this transmission service request to Shell and Shell is now responsible for payment.

Schedule Page: 328 Line No.: 10 Column: h

The contract between Idaho Power and PacifiCorp - Imnaha expires on March 31,2016.

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

Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.

Schedule Page: 328 Line No.: 12 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.: 13 Column: e

5/6, Open Access Transmission Tariff,Schedule 5/6 Operating Reserves.

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

The agreement between Idaho Power and United Materials of Great Falls, Inc. has no expiration date and can be terminated by either party at any time.

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

The agreement between Idaho Power and United Materials of Great Falls, Inc. has no expiration date and can be terminated by either party at any time.

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

7/8, Open Access Transmission Tariff, Schedule 7/8 Point-to-Point Transmission Service.

Schedule Page: 328 Line No.: 16 Column: h
Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328 Line No.: 18 Column: h
Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328 Line No.: 24 Column: h
Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328.1 Line No.: 10 Column: e
7/8, Open Access Transmission tariff, Schedule 7/8 Point-to-Point Transmission Service.
Schedule Page: 328.1 Line No.: 15 Column: h
Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328.1 Line No.: 16 Column: h
Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328.1 Line No.: 17 Column: h
Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328.1 Line No.: 31 Column: h
Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328.1 Line No.: 32 Column: h
Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328.3 Line No.: 25 Column: h
Rate Refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328.4 Line No.: 3 Column: h
Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328.4 Line No.: 6 Column: h
Legacy agrement providing OATT-like service, but billed under 454 facilities revenue.
Schedule Page: 328.4 Line No.: 30 Column: h
Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328.5 Line No.: 8 Column: h
Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328.7 Line No.: 1 Column: h
Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328.7 Line No.: 8 Column: h
Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328.7 Line No.: 12 Column: h
Rate fefund for June 2006 thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328.7 Line No.: 23 Column: h
Rate refund for June 2006, thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328.7 Line No.: 24 Column: h
Rate refund for June 2006 Thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328.7 Line No.: 25 Column: h
Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328.8 Line No.: 30 Column: h
Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328.9 Line No.: 5 Column: h
Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328.9 Line No.: 8 Column: h
Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.
Schedule Page: 328.9 Line No.: 20 Column: h
Rate refund for June 2006 thru April 2014, pursuant to Formula Rat Audit.
Schedule Page: 328.10 Line No.: 6 Column: h
Rate refund for June 2006 thru April 2014, pursuant to Formula Rate Audit.

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	04/15/2015	End of 2014/Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) 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.
4. In column (c) 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 (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
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22					
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25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Avista Corp-WWP Div	NF	30,392	30,392		193,324		193,324
2	Avista Corp-WWP Div	SFP	217,709	217,709		941,879		941,879
3	Avista Corp-WWP Div	AD					-124	-124
4	Bonneville Power Admin	LFP	1,036,928	1,036,928		3,701,617		3,701,617
5	Bonneville Power Admin	SFP	1,840	1,840		9,200		9,200
6	Bonneville Power Admin	NF	364	364		1,820		1,820
7	Bonneville Power Admin	OS	4,220	4,220		21,804		21,804
8	Bonneville Power Admin	OS					3,743	3,743
9	Cargill Power Markets	OS					-420	-420
10	Exelon Generation Co	OS					-70,383	-70,383
11	Ierdrola Renewables	OS					-870	-870
12	Morgan Stanley Capital	OS					-16,664	-16,664
13	NextEra Energy	OS					-6,796	-6,796
14	Northwestern Energy	LFP	4,808	4,808		49,900		49,900
15	NorthWesern Energy	NF	1,716	1,716		5,938		5,938
16	NorthWestern Energy	SFP	14,027	14,027		130,363		130,363
	TOTAL		1,493,306	1,493,306		6,340,973	-259,674	6,081,299

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	04/15/2015	End of 2014/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	PacifiCorp Inc.	LFP	79,660	79,660		779,022		779,022
2	PacifiCorp Inc.	NF	53,945	53,945		291,828		291,828
3	PacifiCorp Inc.	SFP	5,880	5,880		37,134		37,134
4	PaifiCorp Inc.	OS				151,304		151,304
5	PacifiCorp Inc	OS				-41,600		-41,600
6	Powerex Corp.	OS					-136,828	-136,828
7	Puget Sound Energy, Inc	SFP	40,217	40,217		65,040		65,040
8	Sierra Pacific Power Co	NF					-336	-336
9	Snohomish County PUD	SFP	1,200	1,200		1,800		1,800
10	TransAlta Energy U.S.	SFP	400	400		600		600
11	TransAlta Eenrgy U.S.	OS					-30,996	-30,996
12								
13								
14								
15								
16								
	TOTAL		1,493,306	1,493,306		6,340,973	-259,674	6,081,299

Schedule Page: 332 Line No.: 3 Column: a
Unreserved Use Refund

Schedule Page: 332 Line No.: 4 Column: b
Contract Expiration Date 09/30/2016

Schedule Page: 332 Line No.: 8 Column: a
Reserves Provided.

Schedule Page: 332 Line No.: 9 Column: a
Resale Transmission

Schedule Page: 332 Line No.: 10 Column: a
Resale Transmission.

Schedule Page: 332 Line No.: 11 Column: a
Resale Transmission

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

Schedule Page: 332 Line No.: 13 Column: a
Resale Transmission

Schedule Page: 332 Line No.: 14 Column: b
Contract can be terminated at anytime, with 30 days prior notice.

Schedule Page: 332.1 Line No.: 1 Column: b
Contract Expiration Date 05/31/2019

Schedule Page: 332.1 Line No.: 5 Column: a
2012/2013 PTP True Up - PacifiCorp

Schedule Page: 332.1 Line No.: 6 Column: a
Resale Transmission

Schedule Page: 332.1 Line No.: 8 Column: a
Resale Transmission

Schedule Page: 332.1 Line No.: 11 Column: a
Resale Transmission

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	453,508
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	1,682,703
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	67,304
6	Stephen Allred	32,475
7	Thomas Carlile	54,585
8	Richard Dahl	87,057
9	Ronald Jibson	69,622
10	Judith Johnson	74,317
11	Dennis Johnson	69,518
12	J Lamont Keen	38,577
13	Christine King	87,459
14	Jan Packwood	59,865
15	Joan Smith	81,611
16	Robert Tinstman	156,865
17	Thomas Willford	70,729
18		
19	Accociated Taxpayers of Idaho	23,000
20	Boston College for Corporations	5,000
21	Business Plus	5,000
22	Ceati International	13,050
23	Corporate Executive Board	86,120
24	Idaho Association of Commerce & industry	14,000
25	Idaho Technology Council	12,750
26	National Association of Directors	7,125
27	National Hydropower Assoc	33,482
28	North American Energy Standard	7,000
29	Northwest Power pool	279,952
30	Pacific NW Utilities	38,869
31	Utility Variable Generation industry	5,000
32	Western Energy Coordinating Council	1,163,224
33	Western Energy Institute	30,568
34	Misc Memberships under $2,000 (7)	5,915
35		
36	Chambers of Commerce & Other Civic Organizations	91,165
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	4,907,415

Schedule Page: 335 Line No.: 4 Column: b

Recipient	Purpose	Amount
American Stock Transfer & Trust	Mgmt Services	$ 75,181
Broadridge Financial Solutions	Proxy & Bulletin	49,240
Deutsche Bank	Broker Fees	43,482
E Source	Mgmt Services	35,756
Moody's Analytics	Mgmt Services	32,729
NASDAQ Corp Solutions	Mgmt Services	70,138
New York Stock Exchange	Listing Services	46,628
Rate Related Amortization	Misc Expense	230,655
Stock Based Compensation	Misc Expense	752,952
Wells Fargo Shareowner Service	Mgmt Services	115,889
Payroll Related Expenses	Misc Expense	167,051
Miscellaneous		63,002

Total		$1,682,703
		==========

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	04/15/2015	End of 2014/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			7,172,382		7,172,382
2	Steam Production Plant	24,519,352	495,029			25,014,381
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	14,054,949				14,054,949
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	17,190,565				17,190,565
7	Transmission Plant	20,082,639				20,082,639
8	Distribution Plant	40,300,184				40,300,184
9	Regional Transmission and Market Operation					
10	General Plant	9,097,851				9,097,851
11	Common Plant-Electric					
12	TOTAL	125,245,540	495,029	7,172,382		132,912,951

B. Basis for Amortization Charges

Acct 404	Balance 1/1/14	2014 Amortization	Balance 12/31/14	Remaining months
(1)	48,000	12,000	36,000	36
(2)	11,885,442	545,446	10,339,996	-
(3)	5,468,500	189,366	5,251,629	333
(4)	19,158,412	6,115,880	15,747,708	-
(5)	4,035,897	287,899	3,747,997	168
(6)	209,847	8,026	201,821	-
(7)	618,074	13,765	604,625	-
	------------------	-------------	--------------	
Total	40,424,173	7,611,634	35,929,777	

(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) Swan Falls Relicensing (Amortized over a 30 year license period).
(4) Computer Software packages (Amortized over a 60 month period from date of purchase).
(5) Shoshone-Bannock Right of Way (Termination date December 31, 2028).
(6) Boardman Retrofit Tech Analysis (Termination date December 31, 2040).
(7) FERC License Complianc Costs (Termination date will be expirtion date of the FERC Licenses).

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	638	75.00		3.64	R4.0	20.20
13	311.00	150,084	100.00	-10.00	1.89	S1.0	21.30
14	312.10	81,618	60.00	-5.00	1.43	R3.0	21.80
15	312.20	509,205	60.00	-5.00	2.70	R1.5	20.90
16	312.30	4,341	25.00	20.00	2.35	R3.0	7.90
17	314.00	159,337	45.00	-5.00	3.24	S1.0	19.40
18	315.00	70,043	60.00		1.45	S1.5	19.80
19	316.00	11,737	45.00	-5.00	3.68	R0.5	19.00
20	316.10	84	12.00	15.00	8.72	L2.0	6.30
21	316.40	247	12.00	15.00	0.82	L2.0	7.90
22	316.50	83	12.00	15.00	3.19	L2.0	5.10
23	316.60	106	20.00	15.00	4.76	L2.0	18.00
24	316.70	80	20.00	15.00	2.87	L2.0	14.40
25	316.80	3,583	20.00	30.00	3.53	O1.0	16.60
26	316.90	14	35.00	15.00	2.45	S1.0	34.70
27	317.00	6,372					
28	Subtotal Steam	997,572					
29	331.00	175,002	100.00	-25.00	2.38	R2.5	33.00
30	332.10	19,461	95.00	-20.00	1.31	S4.0	39.80
31	332.20	237,646	95.00	-20.00	1.65	S4.0	35.60
32	332.30	5,472			1.44	SQUARE	49.10
33	333.00	207,191	80.00	-5.00	1.72	R3.0	32.60
34	334.00	56,828	50.00	-5.00	2.71	R1.5	26.10
35	335.00	21,069	95.00		2.25	R2.0	28.10
36	335.10	93	15.00		6.86	SQUARE	6.50
37	335.20	366	20.00		5.76	SQUARE	5.30
38	335.30	242	5.00		12.16	SQUARE	3.30
39	336.00	9,585	75.00		2.33	R3.0	21.40
40	Subtotal Hydro	732,955					
41	341.00	140,902			2.83	SQUARE	27.20
42	342.00	10,453	50.00		2.57	S2.5	28.50
43	343.00	238,896	40.00		3.33	S1.5	25.90
44	344.00	66,355	45.00		2.64	S2.0	26.80
45	345.00	88,608	50.00		3.39	S1.5	22.60
46	346.00	6,247	35.00		3.28	S2.5	24.50
47	Subtotal Other	551,461					
48	350.20	31,604	70.00		1.39	R3.0	58.80
49	350.22	115	30.00		3.33		
50	352.00	72,738	65.00	-35.00	1.84	R3.0	53.70

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	353.00	399,788	50.00	-5.00	1.90	R1.5	40.70
13	354.00	168,187	65.00	-15.00	1.70	S3.0	50.80
14	355.00	142,598	60.00	-70.00	2.77	R2.0	43.60
15	356.00	196,361	65.00	-40.00	2.25	R2.0	48.50
16	359.00	390	65.00		0.79	R2.5	24.00
17	Subtotal Transmission	1,011,781					
18	360.22	348	30.00		3.33		30.00
19	361.00	33,717	65.00	-40.00	2.14	R2.5	53.30
20	362.00	202,030	50.00	-5.00	2.00	R1.0	40.20
21	364.00	241,031	44.00	-45.00	3.08	R1.5	31.30
22	364.10	58	12.00		8.34		
23	365.00	128,008	45.00	-35.00	2.98	R0.5	33.60
24	366.00	47,294	60.00	-20.00	1.95	R2.0	48.40
25	367.00	218,657	46.00	-15.00	2.26	R2.0	35.30
26	368.00	494,615	35.00	-3.00	2.58	R1.0	27.00
27	369.00	57,867	40.00	-40.00	2.55	R2.0	29.50
28	370.00	16,483	22.00	1.00	3.46	O1.0	17.50
29	370.10	64,046	15.00		6.96	S2.5	13.10
30	371.10		12.00	-2.00		S4.0	9.00
31	371.20	2,915	17.00	-2.00	1.51	R1.5	14.70
32	373.20	4,505	30.00	-25.00	2.41	R1.0	20.60
33	374.00	534					
34	Subtotal Distribution	1,512,108					
35	390.11	28,255	100.00	-5.00	2.58	S0.5	28.80
36	390.12	78,578	55.00	-5.00	1.90	S0.5	44.30
37	390.20	205	35.00		2.15	S3.0	25.70
38	391.11	14,135	20.00		2.88	SQUARE	12.90
39	391.20	24,364	5.00		11.12	SQUARE	3.20
40	391.21	7,404	8.00		11.22	L2.0	5.70
41	392.10	841	12.00	15.00	7.50	L2.0	8.90
42	392.30	2,920	10.00	50.00	1.73	S2.5	3.40
43	392.40	23,547	12.00	15.00	7.36	L2.0	6.80
44	392.50	1,123	12.00	15.00	3.53	L2.0	9.00
45	392.60	34,652	20.00	15.00	4.14	L2.0	13.40
46	392.70	6,304	20.00	15.00	3.21	L2.0	12.50
47	392.90	4,826	35.00	15.00	2.10	S1.0	24.30
48	393.00	1,936	25.00		3.30	SQUARE	19.40
49	394.00	7,575	20.00		4.13	SQUARE	13.30
50	395.00	12,652	20.00		4.29	SQUARE	12.10

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	04/15/2015	End of 2014/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	396.00	13,938	20.00	30.00	1.66	O1.0	17.60
13	397.10	4,913	15.00		4.25	SQUARE	8.30
14	397.20	32,820	15.00		5.38	SQUARE	9.80
15	397.30	4,330	15.00		5.31	SQUARE	8.00
16	397.40	11,725	10.00		7.90	SQUARE	6.50
17	398.00	5,577	15.00		5.20	SQUARE	10.60
18	Subtotal General	322,620					
19	Total Plant	5,128,497					
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Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/Q4

REGULATORY COMMISSION EXPENSES

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

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Federal Energy Regulatory Commission:				
2	Annual admin charges assessed by FERC	2,598,261		2,598,261	
3					
4	Regulatory FERC fees Tru-up		-89,330	-89,330	
5					
6	General Regulatory Expenses and				
7	Various other Dockets		743,604	743,604	
8					
9	Oregon Hydro - Fees Amortization	158,501		158,501	
10					
11	Regulatory Commission Expenses - Idaho				
12	Rate Case - Misc expenses		-21,427	-21,427	
13					
14	Regulatory Commission Expenses - Oregon				
15	Rate Case - Misc expenses		843	843	
16	General Regulatory		58,643	58,643	
17	Other OPUC expenses		8,743	8,743	
18					
19					
20					
21					
22					
23					
24					
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46	TOTAL	2,756,762	701,076	3,457,838	

REGULATORY COMMISSION EXPENSES (Continued)

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

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
Electric	928	2,598,261					2
							3
Electric	928	-89,330					4
							5
							6
Electric	928	743,604					7
							8
Electric	928	158,501					9
							10
							11
Electric	928	-21,427					12
							13
							14
Electric	928	843					15
Electric	928	58,643					16
Electric	928	8,743					17
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		3,457,838					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	04/15/2015	End of 2014/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	Idaho Power did not incur any Research and	
2	Development expenditures in 2014.	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

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

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
					1
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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	22,607,567		
4	Transmission	6,826,884		
5	Regional Market			
6	Distribution	17,605,437		
7	Customer Accounts	11,413,469		
8	Customer Service and Informational	4,849,214		
9	Sales			
10	Administrative and General	43,649,783		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	106,952,354		
12	Maintenance			
13	Production	4,940,951		
14	Transmission	3,388,364		
15	Regional Market			
16	Distribution	8,231,515		
17	Administrative and General	1,000,896		
18	TOTAL Maintenance (Total of lines 13 thru 17)	17,561,726		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	27,548,518		
21	Transmission (Enter Total of lines 4 and 14)	10,215,248		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	25,836,952		
24	Customer Accounts (Transcribe from line 7)	11,413,469		
25	Customer Service and Informational (Transcribe from line 8)	4,849,214		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	44,650,679		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	124,514,080		124,514,080
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			

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Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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)	124,514,080		124,514,080
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant			
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)			
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	5,014,170		5,014,170
79	Other clearing accounts	3,055,719		3,055,719
80	Construction Work in Progress	53,485,019		53,485,019
81	Other Work in Progress	2,847,464		2,847,464
82	Paid Absences	22,802,332		22,802,332
83	Preliminary Survey and Investigation	760		760
84	Other Accounts	5,388,094		5,388,094
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	92,593,558		92,593,558
96	TOTAL SALARIES AND WAGES	217,107,638		217,107,638

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	04/15/2015	End of 2014/Q4

COMMON UTILITY PLANT AND EXPENSES

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)				
3	Net Sales (Account 447)				
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8					
9					
10					
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40					
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42					
43					
44					
45					
46	TOTAL				

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch						
2	Reactive Supply and Voltage						
3	Regulation and Frequency Response						
4	Energy Imbalance						
5	Operating Reserve - Spinning						
6	Operating Reserve - Supplement						
7	Other						
8	Total (Lines 1 thru 7)						

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	04/15/2015	End of 2014/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	4,791	6	800	3,687	217	567		320	
2	February	4,709	4	800	3,597	220	567		325	
3	March	4,377	19	900	3,097	190	567		523	
4	Total for Quarter 1	13,877			10,381	627	1,701		1,168	
5	April	4,181	7	800	2,827	159	567		628	
6	May	4,818	26	2100	3,488	284	567		479	
7	June	5,496	24	1700	4,364	342	567		223	
8	Total for Quarter 2	14,495			10,679	785	1,701		1,330	
9	July	5,816	14	1400	4,769	357	463		227	
10	August	5,329	11	1600	4,413	274	463		179	
11	September	4,979	16	1700	4,092	248	463		176	
12	Total for Quarter 3	16,124			13,274	879	1,389		582	
13	October	4,175	8	1800	3,345	162	463		205	
14	November	4,792	18	800	4,012	244	463		73	
15	December	4,702	30	1900	3,896	234	463		109	
16	Total for Quarter 4	13,669			11,253	640	1,389		387	
17	Total Year to Date/Year	58,165			45,587	2,931	6,180		3,467	

Schedule Page: 400 Line No.: 17 Column: e

Includes 1836 MW associated with pre-Order No. 888 transmission agreements between PacifiCorp and Idaho Power. The contract demand associated with the pre-Order No. 888 transmission agreements is part of Idaho Power’s total firm load and is included in the load denominator in the computation of, and accordance with, Idaho Power’s Open Access Transmission Tariff (“OATT”) rate. On October 24, 2014, the Parties entered into a Joint Purchase and Sale Agreement and a Termination Agreement that will, if closing occurs, result in the elimination of 1836 MW of contract demand that is associated with the pre-Order No. 888 transmission agreements that terminate as part of the transaction. In addition, 310 MW of Firm Point-To-Point Transmission Service Agreements will become effective if closing occurs. The Parties anticipate all required regulatory approvals will be received and the transaction will close no later than September, 2015.

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	04/15/2015	End of 2014/Q4

MONTHLY ISO/RTO 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 Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
(5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Imports into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

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	04/15/2015	End of 2014/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	14,092,367
3	Steam	5,850,665			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	
5	Hydro-Conventional	6,169,847			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	2,220,419
7	Other	1,174,857			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	13,195,369	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
10	Purchases	4,148,611	27	Total Energy Losses	1,144,985
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	17,457,771
12	Received	324,803			
13	Delivered	211,221			
14	Net Exchanges (Line 12 minus line 13)	113,582			
15	Transmission For Other (Wheeling)				
16	Received	6,721,533			
17	Delivered	6,721,324			
18	Net Transmission for Other (Line 16 minus line 17)	209			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	17,457,771			

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	1,523,503	240,689	2,175	6	9 AM
30	February	1,399,729	314,599	2,204	6	8 AM
31	March	1,328,178	260,659	1,843	12	8 AM
32	April	1,231,532	164,970	1,816	24	10 AM
33	May	1,412,244	82,077	2,436	27	7 PM
34	June	1,636,434	114,271	2,781	23	7 PM
35	July	1,875,812	47,418	3,184	8	6 PM
36	August	1,635,278	199,356	2,949	1	5 PM
37	September	1,398,021	186,995	2,434	16	6 PM
38	October	1,236,921	195,349	1,735	7	6 PM
39	November	1,352,620	207,977	2,253	18	8 AM
40	December	1,423,437	206,059	2,205	31	10 AM
41	TOTAL	17,453,709	2,220,419			

Schedule Page: 401 Line No.: 5 Column: b

The sum of line 12 on pages 406 thru 407 is different than the total on page 401 by 72,413 Mw. The 72,413 Mw is made up of Clear Lakes Power Plant 16,963 Mw and Thousand Springs Power Plant 55,450 Mw. Thousand Springs and Clear lakes is included in the total on page 401 line 5 but they are not included on pages 406-407. They are not included on page 406-407 because plants generating less than 10 Mw are excluded, per instruction 1 on page 406.

Schedule Page: 401 Line No.: 17 Column: b

Page 329 Column I differs from Page 401 by 209 MWH, reported for Lucky Peak variation and BPA Energy imbalalnce 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	04/15/2015	End of 2014/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)	734			62		
7	Plant Hours Connected to Load	8760			6585		
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	4651499000			269335000		
13	Cost of Plant: Land and Land Rights	499457			106610		
14	Structures and Improvements	68495219			12408084		
15	Equipment Costs	480941021			63479074		
16	Asset Retirement Costs	2640264			4348222		
17	Total Cost	552575961			80341990		
18	Cost per KW of Installed Capacity (line 17/5) Including	717.1654			1251.4329		
19	Production Expenses: Oper, Supv, & Engr	265285			537592		
20	Fuel	118487670			6671067		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	5361847			777278		
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	6727902			1020470		
27	Rents	529967			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	77787			198355		
30	Maintenance of Structures	0			65928		
31	Maintenance of Boiler (or reactor) Plant	7416751			262078		
32	Maintenance of Electric Plant	3164373			2123156		
33	Maintenance of Misc Steam (or Nuclear) Plant	5669116			24292		
34	Total Production Expenses	147700698			11680216		
35	Expenses per Net KWh	0.0318			0.0434		
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	2587129	4065	0	161681	1761	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	9174	140000	0	8459	138800	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	43.327	158.528	0.000	41.067	122.529	0.000
41	Average Cost of Fuel per Unit Burned	45.490	118.042	0.000	39.740	126.340	0.000
42	Average Cost of Fuel Burned per Million BTU	2.464	20.075	0.000	2.399	21.673	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.025	0.000	0.000	0.025	0.000	0.000
44	Average BTU per KWh Net Generation	10274.000	0.000	0.000	9983.000	0.000	0.000

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Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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: *Langley Gulch* (b)	Plant Name: (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Gas Turbine	
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	
3	Year Originally Constructed	2012	
4	Year Last Unit was Installed	2012	
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	318.45	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	305	0
7	Plant Hours Connected to Load	4027	0
8	Net Continuous Plant Capability (Megawatts)	300	0
9	When Not Limited by Condenser Water	0	0
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	21	0
12	Net Generation, Exclusive of Plant Use - KWh	1049182000	0
13	Cost of Plant: Land and Land Rights	2287261	0
14	Structures and Improvements	133486018	0
15	Equipment Costs	241890950	0
16	Asset Retirement Costs	0	0
17	Total Cost	377664229	0
18	Cost per KW of Installed Capacity (line 17/5) Including	1185.9451	0
19	Production Expenses: Oper, Supv, & Engr	505916	0
20	Fuel	36289736	0
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	2851598	0
26	Misc Steam (or Nuclear) Power Expenses	301718	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	95463	0
31	Maintenance of Boiler (or reactor) Plant	39718	0
32	Maintenance of Electric Plant	825878	0
33	Maintenance of Misc Steam (or Nuclear) Plant	0	0
34	Total Production Expenses	40910027	0
35	Expenses per Net KWh	0.0390	0.0000

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas					
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF					
38	Quantity (Units) of Fuel Burned	7121881	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1027	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	5.096	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	5.096	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	5.370	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.035	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	6971.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Valmy* (d)	Plant Name: *Danskin* (e)	Plant Name: *Bennett Mountain* (f)	Line No.
Steam	Gas Turbine	Gas Turbine	1
Outdoor	Conventional	Conventional	2
1981	2001	2005	3
1985	2008	2005	4
283.50	270.90	172.80	5
260	244	191	6
6359	414	533	7
0	261	164	8
0	0	0	9
0	0	0	10
0	8	5	11
929831000	55192000	70483000	12
1106140	402745	1688442	13
69181061	5715935	60883807	14
296057640	106887152	0	15
-616367	0	0	16
365728474	113005832	62572249	17
1290.0475	417.1496	362.1079	18
573832	168641	10536	19
31013438	3883525	4881208	20
0	0	0	21
2602142	0	0	22
0	0	0	23
0	0	0	24
1599507	388047	349089	25
1850352	314876	158830	26
554	0	0	27
0	0	0	28
1744	0	0	29
642380	157279	125325	30
3244236	155	5733	31
757425	248261	317289	32
113006	0	0	33
42398616	5160784	5848010	34
0.0456	0.0935	0.0830	35

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
Coal	Oil		Gas			Gas			36
Tons	Barrels		MCF			MCF			37
494841	12308	0	576521	0	0	730067	0	0	38
9407	138778	0	1027	0	0	1027	0	0	39
37.821	136.187	0.000	6.736	0.000	0.000	6.686	0.000	0.000	40
59.159	138.253	0.000	6.736	0.000	0.000	6.686	0.000	0.000	41
3.144	23.719	0.000	6.630	0.000	0.000	6.940	0.000	0.000	42
0.033	0.000	0.000	0.070	0.000	0.000	0.069	0.000	0.000	43
10089.000	0.000	0.000	10728.000	0.000	0.000	10638.000	0.000	0.000	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	04/15/2015	End of 2014/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

(d)			(e)			(f)			Line No.
									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	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: 403 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: 403 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: 403 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	04/15/2015	End of 2014/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)	99	52
7	Plant Hours Connect to Load	4,997	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	264,207,000	301,557,000
13	Cost of Plant		
14	Land and Land Rights	875,318	768,366
15	Structures and Improvements	11,935,359	1,094,991
16	Reservoirs, Dams, and Waterways	4,293,075	8,670,708
17	Equipment Costs	32,743,435	9,409,661
18	Roads, Railroads, and Bridges	839,276	486,477
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	50,686,463	20,430,203
21	Cost per KW of Installed Capacity (line 20 / 5)	549.1491	272.4027
22	Production Expenses		
23	Operation Supervision and Engineering	205,189	822,283
24	Water for Power	1,397,935	666,110
25	Hydraulic Expenses	119,243	648,634
26	Electric Expenses	96,270	41,218
27	Misc Hydraulic Power Generation Expenses	298,420	404,270
28	Rents	143	11,636
29	Maintenance Supervision and Engineering	9,955	7,264
30	Maintenance of Structures	136,098	54,320
31	Maintenance of Reservoirs, Dams, and Waterways	64,125	11,304
32	Maintenance of Electric Plant	271,688	189,883
33	Maintenance of Misc Hydraulic Plant	87,987	153,050
34	Total Production Expenses (total 23 thru 33)	2,687,053	3,009,972
35	Expenses per net KWh	0.0102	0.0100

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	04/15/2015	End of 2014/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)	439	23
7	Plant Hours Connect to Load	8,760	8,756
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	445	25
10	(b) Under the Most Adverse Oper Conditions	137	21
11	Average Number of Employees	5	1
12	Net Generation, Exclusive of Plant Use - Kwh	1,623,091,000	95,302,000
13	Cost of Plant		
14	Land and Land Rights	1,880,381	205,375
15	Structures and Improvements	2,888,412	2,827,184
16	Reservoirs, Dams, and Waterways	52,966,090	6,262,987
17	Equipment Costs	19,847,008	10,262,830
18	Roads, Railroads, and Bridges	922,781	309,505
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	78,504,672	19,867,881
21	Cost per KW of Installed Capacity (line 20 / 5)	200.5228	912.6266
22	Production Expenses		
23	Operation Supervision and Engineering	391,480	100,191
24	Water for Power	252,820	720,714
25	Hydraulic Expenses	706,805	79,575
26	Electric Expenses	241,292	37,156
27	Misc Hydraulic Power Generation Expenses	509,470	112,164
28	Rents	31,631	0
29	Maintenance Supervision and Engineering	19,394	2,766
30	Maintenance of Structures	55,592	38,357
31	Maintenance of Reservoirs, Dams, and Waterways	108,326	16,773
32	Maintenance of Electric Plant	333,032	44,893
33	Maintenance of Misc Hydraulic Plant	427,046	55,550
34	Total Production Expenses (total 23 thru 33)	3,076,888	1,208,139
35	Expenses per net KWh	0.0019	0.0127

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	04/15/2015	End of 2014/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)	34	13
7	Plant Hours Connect to Load	8,760	4,693
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	39	14
10	(b) Under the Most Adverse Oper Conditions	32	11
11	Average Number of Employees	4	2
12	Net Generation, Exclusive of Plant Use - Kwh	191,224,000	42,929,000
13	Cost of Plant		
14	Land and Land Rights	202,398	313,328
15	Structures and Improvements	2,069,321	1,231,506
16	Reservoirs, Dams, and Waterways	6,009,169	4,863,517
17	Equipment Costs	8,908,550	4,703,941
18	Roads, Railroads, and Bridges	29,359	51,383
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	17,218,797	11,163,675
21	Cost per KW of Installed Capacity (line 20 / 5)	499.0956	893.0940
22	Production Expenses		
23	Operation Supervision and Engineering	318,486	183,649
24	Water for Power	241,379	142,205
25	Hydraulic Expenses	368,449	119,810
26	Electric Expenses	92,996	48,168
27	Misc Hydraulic Power Generation Expenses	285,631	233,300
28	Rents	0	28
29	Maintenance Supervision and Engineering	6,650	3,996
30	Maintenance of Structures	85,360	22,470
31	Maintenance of Reservoirs, Dams, and Waterways	25,036	875
32	Maintenance of Electric Plant	85,328	81,483
33	Maintenance of Misc Hydraulic Plant	178,270	119,901
34	Total Production Expenses (total 23 thru 33)	1,687,585	955,885
35	Expenses per net KWh	0.0088	0.0223

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	04/15/2015	End of 2014/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
615	14	209	6
8,760	8,750	8,760	7
			8
747	15	221	9
220	1	202	10
7	2	7	11
1,916,947,000	43,078,000	831,631,000	12
			13
18,232,716	82,142	1,212,767	14
32,155,940	7,364,154	10,709,434	15
67,180,945	3,145,630	30,435,630	16
58,941,432	13,311,381	18,754,552	17
518,444	122,668	565,842	18
0	0	0	19
177,029,477	24,025,975	61,678,225	20
302.4077	1,934.4585	324.6222	21
			22
761,964	242,699	419,169	23
465,585	171,003	245,333	24
1,264,604	440,368	687,208	25
253,884	120,353	212,093	26
1,074,106	331,652	511,962	27
115,980	108	19,016	28
23,312	3,668	15,089	29
103,542	9,618	351,403	30
-12,186	-8	243	31
437,940	86,668	157,025	32
581,357	78,483	233,555	33
5,070,088	1,484,612	2,852,096	34
0.0026	0.0345	0.0034	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	04/15/2015	End of 2014/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
60	18	44	6
8,760	8,751	5,940	7
			8
91	24	53	9
84	14	50	10
5	4	3	11
366,278,000	110,848,000	59,763,000	12
			13
5,476,746	229,890	255,499	14
9,681,585	27,237,723	10,980,059	15
10,806,251	15,906,987	7,975,473	16
13,419,581	30,609,794	21,200,821	17
1,602,868	835,946	1,917,603	18
0	0	0	19
40,987,031	74,820,340	42,329,455	20
495.0125	2,992.8136	802.6063	21
			22
812,529	747,525	177,450	23
641,914	568,175	133,137	24
1,127,584	1,005,213	137,881	25
46,580	33,633	65,024	26
598,565	566,126	166,856	27
61,259	10,179	3,370	28
9,179	6,935	4,052	29
167,971	70,868	31,573	30
79,491	32,468	9,182	31
158,655	153,011	101,736	32
110,131	133,731	85,426	33
3,813,858	3,327,864	915,687	34
0.0104	0.0300	0.0153	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	04/15/2015	End of 2014/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

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

FERC Licensed Project No. 1971 Plant Name: Common Facilities (d)	FERC Licensed Project No. 2061 Plant Name: Lower Salmon (e)	FERC Licensed Project No. 2899 Plant Name: Milner (f)	Line No.
	Run-of-River	Run-of-River	1
	Outdoor	Conventional	2
	1949	1992	3
	1949	1992	4
0.00	60.00	59.45	5
0	36	44	6
0	8,757	3,868	7
			8
0	64	61	9
0	60	1	10
0	5	2	11
0	197,065,000	53,514,000	12
			13
114,367	424,428	138,100	14
40,956,158	2,869,695	10,447,136	15
13,556,785	6,920,148	17,188,307	16
2,096,941	8,149,447	28,835,733	17
99,051	88,693	501,877	18
0	0	0	19
56,823,302	18,452,411	57,111,153	20
0.0000	307.5402	960.6586	21
			22
0	278,036	167,230	23
0	213,833	1,407,513	24
6,911,220	271,860	116,658	25
0	103,894	34,898	26
0	309,322	256,068	27
0	2,869	3,431	28
0	5,001	2,806	29
0	92,696	36,241	30
0	3,267	14,905	31
0	105,375	44,882	32
121,392	79,956	61,778	33
7,032,612	1,466,109	2,146,410	34
0.0000	0.0074	0.0401	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	04/15/2015	End of 2014/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

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

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

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	04/15/2015	End of 2014/Q4

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

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. Plant Name: (c)	FERC Licensed Project No. Plant Name: (d)	FERC Licensed Project No. Plant Name: (e)	Line No.
			1
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2015	End of 2014/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	16,963	3,552,785
3	Thousand Springs	1912	8.80	7.3	55,450	9,460,534
4						
5						
6	Internal Combustion:					
7	Salmon Diesel (1)	1967	5.00	3.0	26	909,259
8						
9						
10						
11	(1) Salmon units are classified as standby.					
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GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
1,421,114	125,875		34,565			2
1,075,061	265,566		186,324			3
						4
						5
						6
181,852				Diesel		7
						8
						9
						10
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Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	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	226.16		1
7	State Line	Midpoint	345.00	345.00	S Tower	76.06		2
8	Kinport	Borah	345.00	345.00	S Tower	27.06		1
9	Jim Bridger	Populus	345.00	345.00	S Tower			1
10	Populus	Kinport	345.00	345.00	S Tower			1
11	Jim Bridger	Populus	345.00	345.00	S Tower			1
12	Populus	Borah	345.00	345.00	S Tower			1
13	Midpoint	Borah #1	345.00	345.00	H Wood	79.30		1
14	Midpoint	Borah #2	345.00	345.00	H Wood	77.58		2
15	Adelaide Tap	Adelaide	345.00	345.00	H Wood	2.67		2
16								
17	Quartz	LaGrande	230.00	230.00	H Wood	46.14		1
18	Midpoint	Hunt	230.00	230.00	S Tower	0.70		2
19	Brady	Antelope	230.00	230.00	H Wood	56.39		1
20	Brady	Treasureton	230.00	230.00	H Wood	0.08		1
21	Brady #1 & #2	Kinport	230.00	230.00	S Tower	17.94		2
22	Jim Bridger	Point of Rocks	230.00	230.00	H Wood	1.40		1
23	Brownlee	Ontario	230.00	230.00	S Tower	72.67		1
24	Mora	Bowmont	138.00	230.00	S P Wood	9.91		1
25	Mora	Bowmont	138.00	230.00	H Wood	8.75		1
26	Jim Bridger	Point of Rocks	230.00	230.00	H Wood	2.79		1
27	Caldwell 710	Locust	230.00	230.00	SP Steel	18.44		1
28	Boise Bench	Caldwell	230.00	230.00	S Tower	7.58		1
29	Boise Bench	Caldwell	230.00	230.00	H Wood	33.49		1
30	Boise Bench	Cloverdale	230.00	230.00	S Tower	15.91		2
31	Boardman	Dalreed Sub	230.00	230.00	H Wood	1.67		1
32	Brownlee 714	Oxbow	230.00	230.00	SP Steel	11.04		2
33	Caldwell	Ontario	230.00	230.00	H Wood	29.97		1
34	Caldwell	Ontario	230.00	230.00	S Tower	3.14		1
35	Bennett Mtn PP	Rattlesnake TS	230.00	230.00	SP Steel	4.44		1
36					TOTAL	4,782.11	11.02	194

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	04/15/2015	End of 2014/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	Hunt	230.00	230.00	H Steel	68.17		1
2	Danskin	Hubbard	230.00	230.00	H Steel	36.25		1
3	Danskin	Hubbard	230.00	230.00	SP Steel	1.84		1
4	Danskin	Hubbard	230.00	230.00	SP Steel	1.30		2
5	Danskin	Bennett Mtn	230.00	230.00	SP Steel	5.32		1
6	Hemingway	Bowmont	230.00	230.00	SP Steel	12.98		1
7	Langley Gulch	Galloway Rd	138.00	230.00	SP Steel	14.19		1
8	Galloway Rd	Willis Tap	138.00	230.00	SP Steel	2.09		1
9	Boise Bench	Midpoint #1	230.00	230.00	S Tower	0.87		1
10	Boise Bench	Midpoint #1	230.00	230.00	H Wood	108.41		1
11	Brownlee	Quartz Jct	230.00	230.00	S Tower	1.51		1
12	Brownlee	Quartz Jct	230.00	230.00	H Wood	41.30		1
13	Brownlee	Boise Bench #1 & #2	230.00	230.00	S Tower	99.76		2
14	Oxbow	Brownlee	230.00	230.00	S Tower	10.32		2
15	Boise Bench	Midpoint #2	230.00	230.00	S Tower	3.49		1
16	Boise Bench	Midpoint #2	230.00	230.00	H Wood	102.07		1
17	Oxbow	Pallette Jct	230.00	230.00	S Tower	20.02		2
18	Pallette Jct	Imnaha	230.00	230.00	H Wood	24.43		2
19	Hells Canyon	Palette Jct	230.00	230.00	S Tower	9.05		2
20	Brownlee	Boise Bench	230.00	230.00	S Tower	102.08		2
21	Boise Bench	Midpoint #3	230.00	230.00	H Wood	106.29		1
22	Palette Jct	Enterprise	230.00	230.00	H Wood	29.60		1
23	Borah	Brady #2	230.00	230.00	S Tower	0.41		1
24	Borah	Brady #2	230.00	230.00	H Wood	3.52		1
25	Borah	Brady #1	230.00	230.00	H Wood	3.84		1
26								
27	Goshen	State Line	161.00	161.00	H Wood	90.69		1
28	Don	Goshen	161.00	161.00	S Tower	2.37		2
29	Don	Goshen	161.00	161.00	H Wood	48.42		2
30								
31	American Falls Power Plant	Adelaide	138.00	138.00	H Wood	11.18		2
32	American Falls Power Plant	Adelaide	138.00	138.00	S P Wood	0.12		2
33	Minidoka Loop	Adelaide	138.00	138.00	S Tower	1.15		2
34	Nampa	Caldwell	138.00	138.00	S P Wood	9.58		2
35	Upper Salmon	Mountain Home Jct	138.00	138.00	H Wood	54.35		1
36					TOTAL	4,782.11	11.02	194

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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TRANSMISSION LINE STATISTICS

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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	Upper Salmon	Cliff	138.00	138.00	H Wood	30.81		1
2	Eastgate	Russet	138.00	138.00	S P Wood	2.08		1
3	Brady	Fremont	138.00	138.00	S Tower	1.00		2
4	Brady	Fremont	138.00	138.00	H Wood	24.38		2
5	Brady	Fremont	138.00	138.00	S P Wood	24.33		2
6	King	Lower Malad	138.00	138.00	H Wood	84.74		2
7	Emmett Jct	Payette	138.00	138.00	H Wood	66.47		2
8	Mountain Home AFB Tap		138.00	138.00	H Wood	6.20		1
9	Ontario	Quartz	138.00	138.00	H Wood	73.27		1
10	King	American Falls PP	138.00	138.00	S Tower	1.01		2
11	King	American Falls PP	138.00	138.00	H Wood	142.03		1
12	King	American Falls PP	138.00	138.00	S P Wood	3.71		1
13	Duffin	Clawson	138.00	138.00	H Wood	6.19		1
14	American Falls	Brady Tie	138.00	138.00	H Wood	0.33		1
15	Upper Salmon A-B	King	138.00	138.00	H Wood	5.66		1
16	Upper Salmon B	Wells	138.00	138.00	H Wood	125.59		1
17	King	Wood River	138.00	138.00	H Wood	73.60		1
18	Boise Bench	Grove	138.00	138.00	S P Wood	10.31		2
19	Quartz	John Day	138.00	138.00	H Wood	67.13		1
20	Sinker Creek Tap		138.00	138.00	H Wood	2.79		1
21	Mora	Cloverdale	138.00	138.00	H Wood	2.51		1
22	Mora	Cloverdale	138.00	138.00	S P Wood	22.28		1
23	Mora	Cloverdale	138.00	138.00	S P Steel	0.96		2
24	Stoddard Jct	Stoddard Sub	138.00	138.00	S P Steel	3.80		1
25	Fossil Gulch Tap		138.00	138.00	H Wood	1.81		1
26	Wood River	Midpoint	138.00	138.00	H Wood	53.08		2
27	Wood River	Midpoint	138.00	138.00	S P Wood	16.69		2
28	Oxbow	McCall	138.00	138.00	H Wood	37.15		1
29	Oxbow	McCall	138.00	138.00	S P Wood	2.32		1
30	Lowell Jct	Nampa	138.00	138.00	S P Wood	7.47		2
31	Hunt	Milner	138.00	138.00	S P Wood	19.40		1
32	Strike	Bruneau Bridge	138.00	138.00	H Wood	13.49		1
33	American Falls	Kramer Sub	138.00	138.00	S P Wood	18.46		2
34	Pingree	Haven	138.00	138.00	S P Wood	11.72		1
35	Midpoint	Twin Falls	138.00	138.00	S P Wood	25.21		2
36					TOTAL	4,782.11	11.02	194

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TRANSMISSION LINE STATISTICS

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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	Twin Falls	Russett	138.00	138.00	S P Wood	1.69		1
2	Blackfoot	Aiken	46.00	138.00	S P Wood	6.17		2
3	Peterson	Tendoy	69.00	138.00	H Wood	57.21		1
4	Eastgate Tap	Eastgate	138.00	138.00	S P Wood	6.36		1
5	Kimberly Tap	Kimberly	138.00	138.00	S P Steel	1.84		2
6	Boise Bench	Mora	138.00	138.00	H Wood	13.10		2
7	Bowmont-Caldwell	Simplot Sub	138.00	138.00	S P Wood	0.51		1
8	Gary Lane	Eagle	138.00	138.00	S P Wood	6.52		1
9	Locust Grove	Blackcat Sub	138.00	138.00	S P Steel	9.25	2.98	1
10	Boise Bench	Butler	138.00	138.00	S P Wood	0.14	4.02	1
11	Eagle	Star	138.00	138.00	S P Wood	6.73		1
12	Karcher Sub	Zilog Tap	138.00	138.00	S P Steel	3.60		1
13	Cloverdale - 712	712 - Wye	138.00	138.00	S P Steel	0.42	4.02	1
14	Victory Jct	Victory	138.00	138.00	S P Steel	1.89		1
15	Butler	Wye	138.00	138.00	S P Steel	2.94		1
16	Horseflat	Starkey	138.00	138.00	H Wood	33.97		1
17	Starkey	Mccall	138.00	138.00	S P Steel	2.23		2
18	Starkey	Mccall	138.00	138.00	H Wood	3.80		1
19	Starkey	Mccall	138.00	138.00	S P Steel	1.50		1
20	Starkey	Mccall	138.00	138.00	S P Wood	17.61		1
21	Chestnut	Happy Valley	138.00	138.00	S P Steel	2.78		1
22	Garnet	Ward		138.00				
23	McCall	Lake Fork	138.00	138.00	S P Wood	8.89		1
24	McCall	Lake Fork	138.00	138.00	S Steel	2.90		
25	Caldwell	Willis	138.00	138.00	S P Steel	1.30		1
26	Caldwell	Willis	138.00	138.00	S P Steel	1.59		1
27	Caldwell	Willis	138.00	138.00	S P Wood	0.87		1
28	Valivue Tap		138.00	138.00	S P Steel	0.79		2
29	Bowmont	Happy Valley	138.00	138.00	S P Steel	8.64		1
30	Kinport	Don #1	138.00	138.00	S Tower	1.32		2
31	Donn	HOKU	138.00	138.00	S P Steel	2.71		1
32	HOKU	Alamed	138.00	138.00	S P Steel	0.22		2
33	HOKU	Alamed	138.00	138.00	S P Steel	0.23		2
34	HOKU	Alamed	138.00	138.00	S P Steel	2.85		1
35	Rockland Jct	Rockland Wind Farm	138.00	138.00	S P Steel	5.26		1
36					TOTAL	4,782.11	11.02	194

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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	Justice	138.00	138.00	S P Wood	0.07		1
2	Twin Falls PP Tap		138.00	138.00	H Wood	0.82		1
3	American Falls PP	Amercian Falls Trans ST	138.00	138.00	S P Steel	0.20		1
4	Lower Salmon	King Tie	138.00	138.00	H Wood	0.11		1
5	C J Strike	Strike Jct	138.00	138.00	S Tower	4.30		2
6	Strike Jct	Mountain Home Jct	138.00	138.00	H Wood	23.42		1
7	Strike Jct	Bowmont		138.00	H Wood	0.05		1
8	Strike Jct	Bowmont	138.00	138.00	S Tower	0.36		1
9	Strike Jct	Bowmont	138.00	138.00	H Wood	68.02		1
10	Lucky Peak	Lucky Peak Jct	138.00	138.00	H Wood	4.48		2
11	Bliss	King	138.00	138.00	H Wood	10.47		1
12	Milner Deadend	Milner PP	138.00	138.00	S P Wood	1.30		1
13	Swan Falls Tap		138.00	138.00	H Wood	0.95		1
14								
15								
16								
17	Hines	BPA (Harney)	115.00	115.00	H Wood	3.35		1
18								
19								
20	69 Kv Lines		69.00	69.00	H Wood	167.03		1
21	69 Kv Lines		69.00	69.00	S P Wood	937.02		1
22								
23								
24	46 Kv Lines		46.00	46.00	S P Wood	408.37		1
25								
26	Total all lines					4,782.11	11.02	194
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	4,782.11	11.02	194

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
1272 ACSR	256,381	21,828,404	22,084,785					1
2X1780 ACSR		446,708	446,708					2
1272 ACSR		835,662	835,662					3
1272 ACSR								4
								5
1272 ACSR	483,309	16,830,982	17,314,291					6
795 ACSR	571,979	11,108,161	11,680,140					7
1272 ACSR	344,220	6,008,061	6,352,281					8
1272 ACSR		10,157,447	10,157,447					9
1272 ACSR								10
1272 ACSR		1,035,143	1,035,143					11
1272 ACSR								12
715.5 ACSR	283,143	13,335,498	13,618,641					13
715.5 ACSR	64,851	15,402,643	15,467,494					14
715.5 ACSR	51,448	347,946	399,394					15
								16
795 ACSR	62,218	5,437,966	5,500,184					17
715.5 ACSR	9,145	998,452	1,007,597					18
1272 ACSR	108,301	3,415,845	3,524,146					19
795 ACSR		6,186	6,186					20
715.5 ACSR	18,829	969,871	988,700					21
1272 ACSR	1,190	51,525	52,715					22
2X954 ACSR	1,676,838	20,541,790	22,218,628					23
715.5 ACSR	413,793	2,197,386	2,611,179					24
715.5 ACSR								25
1272 ACSR	1,899	212,523	214,422					26
1590 ACSR	2,138,236	8,775,086	10,913,322					27
1272 ACSR	1,748,214	7,403,554	9,151,768					28
715.5 ACSR								29
1272 ACSR	3,062,812	6,560,901	9,623,713					30
795 AAC		89,694	89,694					31
954 ACSR	34,174	16,026,470	16,060,644					32
2X954 ACSR	236,152	9,228,893	9,465,045					33
1272 ACSR								34
1272 ACSR	81,701	1,666,354	1,748,055					35
	32,046,045	516,707,077	548,753,122	7,400,901	3,369,518	3,284,850	14,055,269	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.
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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.
1590 ACSR	624,917	22,468,666	23,093,583					1
1590 ACSR		15,210,561	15,210,561					2
1590 ACSR								3
1590 ACSR								4
1590 ACSR		3,528,033	3,528,033					5
1590 ACSR	1,854,996	9,332,649	11,187,645					6
1590 ACSR	948,166	9,080,890	10,029,056					7
1272 ACSR								8
715.5 ACSR	385,287	6,739,866	7,125,153					9
715.5 ACSR								10
795 ACSR	53,068	2,833,575	2,886,643					11
795 ACSR								12
VARIOUS	289,934	8,966,987	9,256,921					13
1272 ACSR	14,810	1,237,524	1,252,334					14
715.5 ACSR	227,825	14,141,042	14,368,867					15
VARIOUS								16
1272 ACSR	87,468	4,031,934	4,119,402					17
1272 ACSR	171,081	1,651,381	1,822,462					18
1272 ACSR	44,687	1,252,130	1,296,817					19
954 ACSR	184,817	6,257,154	6,441,971					20
715.5 ACSR	247,857	5,663,803	5,911,660					21
1272 ACSR	84,014	1,867,303	1,951,317					22
1272 ACSR	3,068	416,606	419,674					23
715.5 ACSR								24
1272 ACSR	7,248	421,273	428,521					25
								26
250 COPPER	16,155	648,382	664,537					27
715.5 ACSR	88,204	2,343,558	2,431,762					28
397.5 ACSR								29
								30
250 COPPER	26,507	381,182	407,689					31
250 COPPER								32
715.5 ACSR	21,327	249,232	270,559					33
795 AAC	670,449	3,200,265	3,870,714					34
795 ACSR	47,687	3,539,654	3,587,341					35
	32,046,045	516,707,077	548,753,122	7,400,901	3,369,518	3,284,850	14,055,269	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	04/15/2015	End of 2014/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
795 ACSR	43,568	1,882,280	1,925,848					1
795 AAC	270,823	557,504	828,327					2
VARIOUS	564,932	4,080,596	4,645,528					3
VARIOUS								4
VARIOUS								5
VARIOUS	76,823	3,208,627	3,285,450					6
VARIOUS	33,918	2,734,762	2,768,680					7
397.5 ACSR	1,955	6,930	8,885					8
VARIOUS	34,428	5,204,281	5,238,709					9
715.5 ACSR	216,919	9,014,734	9,231,653					10
715.5 ACSR								11
715.5 ACSR								12
4\0	4,191	351,881	356,072					13
954 ACSR		96,921	96,921					14
250 COPPER	2,741	761,189	763,930					15
VARIOUS	28,490	3,049,994	3,078,484					16
VARIOUS	173,683	3,804,937	3,978,620					17
VARIOUS	225,602	1,652,772	1,878,374					18
397.5 ACSR	92,173	2,450,153	2,542,326					19
VARIOUS	20	77,199	77,219					20
715.5 ACSR	3,123,380	8,615,808	11,739,188					21
VARIOUS								22
795AAC								23
1272 ACSR								24
250 COPPER	450	187,848	188,298					25
397.5 ACSR	349,712	7,070,008	7,419,720					26
397.5 ACSR								27
397.5 ACSR	141,534	2,698,198	2,839,732					28
397.5 ACSR								29
715.5 ACSR	211,131	1,457,085	1,668,216					30
715.5 ACSR	3,324	1,416,503	1,419,827					31
397.5 ACSR	14,927	687,321	702,248					32
715.5 ACSR	13,734	1,052,339	1,066,073					33
397.5 ACSR	18,223	1,281,344	1,299,567					34
VARIOUS	54,848	3,086,512	3,141,360					35
	32,046,045	516,707,077	548,753,122	7,400,901	3,369,518	3,284,850	14,055,269	36

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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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	16,790	210,756	227,546					1
715.5 ACSR	13,616	529,756	543,372					2
397.5 ACSR	395,696	3,443,681	3,839,377					3
715.5 ACSR	343,955	2,142,718	2,486,673					4
795 ACSR								5
715.5 ACSR	14,697	718,864	733,561					6
795 AAC		49,642	49,642					7
795 AAC	489,037	2,165,954	2,654,991					8
1272 ACSR	935,810	3,503,157	4,438,967					9
1272 ACSR	34,687	838,605	873,292					10
715.5 ACSR	179,817	3,270,853	3,450,670					11
795 AAC	43,035	434,341	477,376					12
1272 ACSR	140,412	2,577,075	2,717,487					13
1272 ACSR								14
795 ACSR	134,471	1,405,436	1,539,907					15
715.5 ACSR	2,473,833	19,385,962	21,859,795					16
715.5 ACSR								17
715.5 ACSR								18
715.5 ACSR								19
715.5 ACSR								20
1272 ACSR	78,579	2,259,301	2,337,880					21
	40,580		40,580					22
715.5 ACSR	331,539	4,682,879	5,014,418					23
								24
1272 ACSR	272,231	2,141,218	2,413,449					25
795 ACSR								26
795 ACSR								27
795 ACSR		351,497	351,497					28
1272 ACSR	690,611	6,015,350	6,705,961					29
715.5 ACSR	1,174	212,777	213,951					30
1272 ACSR	190	4,584	4,774					31
1272 ACSR								32
795 ACSR								33
795 ACSR								34
795 ACSR		-16,973	-16,973					35
	32,046,045	516,707,077	548,753,122	7,400,901	3,369,518	3,284,850	14,055,269	36

TRANSMISSION LINE STATISTICS (Continued)

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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		60,659	60,659					1
250 COPPER	58	63,264	63,322					2
715.5 ACSR		76,560	76,560					3
397.5 ACSR		4,406	4,406					4
715.5 ACSR	1,074	622,115	623,189					5
397.5 ACSR	6,332	2,563,423	2,569,755					6
715.5 ACSR	86,651	2,429,399	2,516,050					7
715.5 ACSR								8
								9
715.5 ACSR	7	279,481	279,488					10
715.5 ACSR	5,620	997,718	1,003,338					11
715.5 ACSR	2,814	183,606	186,420					12
397.5 ACSR	12,885	261,511	274,396					13
								14
								15
								16
397.5 ACSR	1,978	63,404	65,382					17
								18
								19
VARIOUS	1,653,396	62,432,378	64,085,774					20
VARIOUS								21
								22
								23
VARIOUS	194,536	17,471,193	17,665,729					24
				7,400,901	3,369,518	3,284,850	14,055,269	25
	32,046,045	516,707,077	548,753,122	7,400,901	3,369,518	3,284,850	14,055,269	26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	32,046,045	516,707,077	548,753,122	7,400,901	3,369,518	3,284,850	14,055,269	36

Schedule Page: 422 Line No.: 9 Column: a

Lines 808 amd 809 are not Idaho Power Company they are the Company portion of investment into the Populus Station Lines

Schedule Page: 422 Line No.: 10 Column: a

Lines 808 and 809 are not Idaho Power Company they are the Company's portion of investment into the Populus station lines.

Schedule Page: 422 Line No.: 11 Column: a

Lines 808 and 809 are not Idaho Power Company they are the Company's portion of investment into the Populus station lines.

Schedule Page: 422 Line No.: 12 Column: a

Lines 808 and 809 are not Idaho Power Company they are the Company's portion of investment into the Populus station lines.

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	04/15/2015	End of 2014/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		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)	(c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	Bowmont	Happy Valley	8.64	S Pole	17.70	1	1
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	TOTAL		8.64		17.70	1	1

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
1272	ACSR	TVS	138	690,611	3,384,477	2,630,873		6,705,961	1
									2
									3
									4
									5
									6
									7
									8
									9
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									12
									13
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				690,611	3,384,477	2,630,873		6,705,961	44

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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	transmission	230.00	138.00	13.80
30	Brady	transmission	138.00	46.00	12.47
31	Brady	distribution	69.00	13.00	
32	Brownlee - attended	transmission	230.00	13.80	
33	Bruneau Bridge	distribution	138.00	35.00	
34	Bruneau Bridge	distribution	138.00	36.20	
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	

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	04/15/2015	End of 2014/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	Caldwell	transmission	230.00	138.00	
2	Caldwell	distribution	138.00	13.09	
3	Caldwell	transmission	138.00	69.00	12.47
4	Caldwell	transmission	230.00	138.00	12.47
5	Caldwell	distribution	13.00	4.16	
6	Canyon Creek	distribution	138.00	35.00	
7	Canyon Creek	transmission	138.00	69.00	12.98
8	Cascade Power Plant - attended	transmission	69.00	4.60	
9	Cascade	distribution	69.00	13.10	
10	Cascade	distribution	25.00		
11	Chestnut	distribution	138.00	13.00	
12	Clear Lake - attended	transmission	46.00	2.40	
13	Cliff	transmission	138.00	46.00	12.50
14	Cliff	transmission	138.00	46.00	12.95
15	Cloverdale	distribution	138.00	13.00	
16	Dale	distribution	46.00	4.60	
17	Dale	distribution	46.00	13.00	
18	Dale	distribution	69.00	13.00	
19	Dale	distribution	138.00	36.20	
20	Dale	transmission	138.00	46.00	12.47
21	Danskin- attended	transmission	230.00	18.00	
22	Danskin- attended	transmission	230.00	138.00	13.80
23	Danskin- attended	distribution	18.00	4.16	
24	Danskin- attended	transmission	138.00	12.00	
25	Danskin- attended	distribution	35.00	13.80	
26	Don	distribution	138.00	7.60	
27	Don	distribution	138.00	13.20	
28	Don	distribution	138.00	13.00	
29	Don	distribution	14.00		
30	DRAM	distribution	138.00	13.09	
31	DRAM	transmission	230.00	138.00	13.80
32	DRAM	distribution	138.00	12.47	
33	Duffin	distribution	138.00	35.00	
34	Eagle	distribution	138.00	13.09	
35	Eastgate	distribution	138.00		
36	Eastgate	distribution	138.00	13.00	
37	Eckert	distribution	138.00	36.20	
38	Eden	distribution	138.00	36.20	
39	Eden	transmission	138.00	46.00	12.98
40	Elkhorn	distribution	138.00	12.47	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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	Elkhorn	distribution	138.00	13.00	
2	Elmore	distribution	138.00	35.00	
3	Elmore	transmission	138.00	69.00	12.50
4	Elmore	transmission	138.00	69.00	12.98
5	Emmett	distribution	138.00		
6	Emmett	transmission	138.00	69.00	12.47
7	Falls	distribution	46.00	13.00	
8	Falls	distribution	46.00		
9	Filer	distribution	46.00	13.00	
10	Flat Top	distribution	46.00	13.00	
11	Flying H	distribution	69.00	2.40	
12	Fort Hall	distribution	46.00	13.00	
13	Fossil Gulch	distribution	138.00	35.00	
14	Fremont	transmission	138.00	46.00	12.50
15	Gary	distribution	138.00	13.09	
16	Gary	distribution	138.00	13.00	
17	Gem	distribution	69.00	13.00	
18	Gem	distribution	69.00		
19	Goodng Rural	distribution	46.00	13.00	
20	Golden Valley	distribution	69.00	13.00	
21	Gowen Substation	distribution	138.00	35.00	
22	Grindstone	distribution	35.00		
23	Grove	distribution	138.00	13.09	
24	Grove	distribution	138.00	13.00	
25	Hagerman	distribution	46.00	13.00	
26	Hagerman	distribution	69.00	13.00	
27	Hailey	distribution	138.00	13.00	
28	Happy Valley	distribution	138.00	13.09	
29	Haven	distribution	138.00	35.00	
30	Haven	transmission	138.00	46.00	
31	Hemingway	transmission	500.00	230.00	34.50
32	Hewlett Packard	distribution	138.00	13.00	
33	Hidden Springs	distribution	138.00	13.00	
34	Highland	distribution	138.00	13.00	
35	Hill	distribution	138.00	13.00	
36	Hillsdale	distribution	138.00		
37	Hoku	distribution	138.00	13.80	
38	Homedale	distribution	69.00	13.00	
39	Horse Flat	transmission	230.00	138.00	13.80
40	Horseshoe Bend	distribution	35.00		

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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	Horseshoe Bend	distribution	69.00	36.20	
2	Horseshoe Bend	distribution	69.00	25.00	
3	Huston	distribution	69.00	13.00	
4	Hulen	distribution	46.00	13.00	
5	Hunt	transmission	230.00	138.00	13.80
6	Hydra	distribution	138.00	36.20	
7	Island	distribution	69.00	13.00	
8	Jerome	distribution	138.00	13.00	
9	Jerome	distribution	138.00	13.09	
10	Julion Clawson	distribution	138.00	35.00	
11	Joplin	distribution	138.00	13.00	
12	Joplin	distribution	138.00	35.00	
13	Justice	transmission	230.00	138.00	13.80
14	Karcher	distribution	138.00	13.00	
15	Kenyon	distribution	69.00	13.00	
16	Ketchum	distribution	138.00	13.00	
17	Kimberly	distribution	138.00	13.00	
18	Kinport	transmission	161.00	46.00	13.20
19	Kinport	transmission	230.00	138.00	12.47
20	Kinport	transmission	230.00	138.00	13.80
21	Kinport	transmission	345.00	230.00	13.80
22	Kramer	distribution	138.00	35.00	
23	Kramer	distribution	138.00	36.20	
24	Kuna	distribution	138.00	13.00	
25	Lake	distribution	69.00	13.00	
26	Lake Fork	distribution	138.00	36.20	
27	Lake Fork	transmission	138.00	69.00	12.50
28	Lamb	distribution	138.00	13.00	
29	Langley Gulch- attended	transmission	230.00	138.00	13.80
30	Langley Gulch- attended	transmission	230.00		
31	Langley Gulch- attended	distribution		4.16	
32	Langley Gulch- attended	distribution	13.00	4.16	
33	Lansing	distribution	69.00	13.00	
34	Lincoln	distribution	138.00	13.09	
35	Linden	distribution	138.00	13.00	
36	Locust	distribution	138.00	36.20	
37	Locust	transmission	230.00	138.00	13.80
38	Lower Malad - attended	transmission	138.00	7.20	
39	Lower Salmon - attended	transmission	138.00	13.80	
40	Map Rock	distribution	69.00	13.00	

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	04/15/2015	End of 2014/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	McCall	distribution	13.00	13.09	
2	McCall	distribution	138.00	36.20	
3	Meridian	distribution	138.00	13.00	
4	Micron	distribution	138.00	13.09	
5	Micron	distribution	138.00	13.00	
6	Midpoint	transmission	230.00	138.00	13.80
7	Midpoint	transmission	345.00	230.00	13.80
8	Midpoint	transmission	500.00	345.00	
9	Midrose	distribution	138.00	13.09	
10	Milner	transmission	138.00	69.00	12.47
11	Milner	distribution	69.00	46.00	6.90
12	Milner	distribution	138.00	35.00	
13	Milner PP - attended	transmission	138.00	13.80	
14	Moonstone	distribution	138.00	35.00	
15	Mora	distribution	138.00	35.00	
16	Mora	distribution	138.00	36.20	
17	Moreland	distribution	35.00	13.00	
18	Moreland	distribution	46.00	13.00	
19	Moreland	distribution	46.00	35.00	12.47
20	Mountain Home	distribution	69.00	13.00	
21	Mountain Home Air Force Base	distribution	69.00	13.00	
22	Mountain Home Air Force Base	distribution	138.00	13.00	
23	Nampa	transmission	230.00	138.00	13.80
24	Nampa	distribution	138.00	13.00	
25	New Meadows	distribution	138.00	36.20	
26	New Plymouth	distribution	69.00	13.00	
27	Notch Butte	distribution	138.00	13.09	
28	Orchard	distribution	69.00	36.20	
29	Orchard	distribution	69.00	35.00	12.47
30	Parma	distribution	69.00	13.00	
31	Parma	distribution	69.00	35.00	
32	Paul	distribution	138.00	35.00	
33	Payette	distribution	138.00	13.00	
34	Pingree	transmission	138.00	46.00	12.50
35	Pingree	distribution	138.00	35.00	
36	Pleasant Valley	distribution	138.00	35.00	
37	Pocatello	distribution	46.00	13.00	
38	Poleline	distribution	138.00	13.09	
39	Populus	transmission	345.00		
40	Portneuf	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) 04/15/2015	Year/Period of Report End of 2014/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	Portneuf	distribution	46.00	35.00	
2	Rockford	distribution	46.00	13.00	
3	Russett	distribution	138.00	13.00	
4	Sailor Creek	distribution	138.00	2.40	
5	Sailor Creek	distribution	138.00	35.00	
6	Salmon	distribution	69.00	13.00	
7	Salmon	distribution	69.00	34.50	12.47
8	Salmon	distribution	69.00		12.47
9	Salmon	transmission	13.00	2.40	
10	Shoshone	distribution	46.00	13.00	
11	Shoshone	distribution	46.00	7.20	
12	Shoshone Falls - attended	transmission	46.00	2.30	
13	Shoshone Falls - attended	transmission	46.00	6.60	
14	Silver	distribution	138.00	35.00	
15	Simplot	distribution	138.00	13.00	
16	Sinker Creek	distribution	138.00	35.00	
17	Siphon	distribution	138.00	35.00	
18	South Park	distribution	46.00	13.00	
19	Star	distribution	138.00	13.09	
20	Starkey	transmission	138.00	69.00	12.47
21	State	distribution	69.00	13.00	
22	Stoddard	distribution	138.00	13.00	
23	Strike Power Plant - attended	transmission	138.00	13.80	
24	Sugar	distribution	138.00	35.00	
25	Swan Falls - attended	transmission	138.00	6.90	
26	Taber	distribution	46.00	13.00	
27	Ten Mile	distribution	138.00	13.09	
28	Terry	distribution	138.00	13.09	
29	Terry	distribution	138.00	13.00	
30	Thousand Springs - attended	transmission	46.00	7.20	
31	Thousand Springs - attended	transmission	7.00	2.40	
32	Toponis	distribution	138.00	33.00	
33	Twin Falls	distribution	138.00	13.09	
34	Twin Falls	transmission	138.00	46.00	12.98
35	Twin Falls PP - attended	transmission	138.00	7.20	
36	Twin Falls PP - attended	transmission	138.00	13.20	
37	Upper Malad - attended	transmission	45.00	7.20	
38	Upper Salmon- attended	transmission	138.00	7.20	
39	Ustick	distribution	138.00	13.00	
40	Vallivue	distribution	138.00	13.09	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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	Victory	distribution	138.00	13.00	
2	Victory	distribution	138.00	13.09	
3	Ware	distribution	69.00	13.00	
4	Weiser	distribution	69.00	13.00	
5	Weiser	transmission	138.00	69.00	12.47
6	Wilder	distribution	69.00	13.00	
7	Willis	distribution	138.00	13.09	
8	Wye	distribution	138.00	13.00	
9	Wye	distribution	138.00	13.09	
10	Zilog	distribution	138.00	13.09	
11					
12					
13	The above are all State of Idaho				
14					
15	Montana:				
16	Peterson	transmission	230.00	69.00	13.20
17					
18	Nevada:				
19	Valmy - attended	transmission	345.00	125.00	24.90
20	Valmy - attended	transmission	345.00	125.00	24.90
21	Valmy - attended	transmission	120.00	24.90	7.20
22	Valmy - attended	transmission	345.00		
23	Valmy - attended	transmission	345.00		
24	Valmy - attended	transmission	345.00		
25	Valmy - attended	transmission	345.00		
26	Valmy - attended	transmission	345.00		
27	Wells	transmission	138.00	69.00	13.00
28					
29	Oregon:				
30	Boardman - attended	transmission	500.00	24.00	
31	Boardman - attended	transmission	230.00	7.20	
32	Boardman - attended	transmission	24.00	7.20	
33	Cairo	distribution	69.00	13.00	
34	Hells Canyon - attended	transmission	230.00	13.80	
35	Hells Canyon - attended	distribution	69.00	0.50	
36	Hines	transmission	138.00	115.00	12.47
37	Malheur Butte	distribution	69.00	34.50	
38	Nyssa	distribution	69.00	13.00	
39	Ontario	distribution	138.00	13.00	
40	Ontario	transmission	138.00	69.00	12.47

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	04/15/2015	End of 2014/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	Ontario	transmission	230.00	138.00	13.80
2	Ontario	transmission	138.00	69.00	12.98
3	Ontario	transmission	138.00	69.00	13.09
4	Ore-Ida	distribution	69.00	13.00	
5	Oxbow - attended	transmission	138.00	69.00	13.00
6	Oxbow - attended	transmission	230.00	13.80	
7	Oxbow - attended	transmission	230.00	138.00	13.80
8	Quartz	transmission	138.00	69.00	12.50
9	Quartz	transmission	230.00	138.00	12.98
10	Quartz	transmission	138.00	69.00	12.98
11	Vale	distribution	69.00	13.00	
12					
13	Wyoming:				
14	Jim Bridger - attended	transmission	345.00	230.00	34.50
15					
16					
17					
18					
19					
20	Transformers-distribution substations under 10,000				
21	KVA 83 unattended.				
22					
23					
24					
25					
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Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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)	
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
312	3					29
		1				30
		1				31
721	5	1				32
18	1					33
24	1					34
20	1					35
6	1	1				36
20	2					37
12	1					38
48	2					39
15	1					40

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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)	
120	1					1
24	1					2
75	3					3
120	1					4
		1				5
15	1					6
15	1					7
12	1					8
15	2					9
4	1					10
48	2					11
4	1					12
12	2	1				13
4	1					14
48	2					15
		1				16
		6				17
		1				18
27	1					19
25	1					20
140	1					21
180	1					22
6	1					23
96	2					24
5	1					25
		1				26
108	6	3				27
26	1	1				28
80	6					29
118	7					30
160	2					31
17	1					32
36	2					33
38	2					34
24	1					35
18	1					36
18	1					37
24	1					38
15	1					39
8	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.
8	1					1
17	1					2
15	1					3
15	1					4
24	1					5
25	1					6
8	1					7
10	1					8
10	1					9
13	2					10
15	2					11
10	1	1				12
15	1					13
50	3	1				14
20	1					15
17	1					16
8	1					17
10	1					18
15	2					19
10	1	1				20
24	1					21
10	2					22
48	2					23
24	1					24
10	1					25
5	1					26
20	1					27
18	1					28
12	1					29
25	1					30
600	3	1				31
20	1					32
8	1					33
18	1					34
39	2					35
24	1					36
		2				37
22	2					38
100	1					39
5	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.
12	1					1
5	1					2
10	1					3
10	1					4
300	3					5
48	2					6
12	1					7
20	1					8
20	1					9
30	2					10
15	1					11
18	1					12
180	1					13
12	1					14
20	2					15
42	2					16
18	1					17
		7				18
180	1					19
180	1					20
600	3	1				21
12	1					22
18	1					23
15	1					24
10	1					25
18	1					26
15	1					27
18	1					28
180	1					29
246	2					30
12	1					31
12	1					32
12	1					33
10	1					34
33	2					35
48	2	1				36
360	2					37
16	1					38
70	4					39
10	1					40

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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)	
12	1					1
18	1					2
36	2					3
24	2					4
24	2					5
120	1					6
840	2	1				7
750	3					8
24	1					9
75	3	1				10
8	3	1				11
29	2					12
36	1					13
12	1					14
15	1					15
24	1					16
6	1					17
8	1					18
6	3	1				19
15	1					20
		1				21
18	1					22
180	1					23
50	3					24
12	1					25
10	1					26
10	1					27
6	1					28
10	3					29
10	1					30
12	1					31
36	2					32
23	3					33
50	3					34
22	2					35
42	2					36
36	2					37
18	1					38
						39
18	1					40

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2015	Year/Period of Report End of 2014/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.
		1				1
14	2					2
18	1					3
15	2					4
15	1					5
10	1	3				6
10	3					7
		2				8
5	2					9
10	1					10
2	3					11
3	1					12
10	1					13
12	1					14
30	2					15
12	1					16
33	2					17
10	1					18
18	1					19
18	1					20
33	2					21
15	1					22
83	3					23
20	2					24
18	1					25
5	1					26
24	1					27
12	1					28
30	2					29
8	1					30
		1				31
18	1					32
44	2					33
33	2					34
9	1					35
72	1					36
8	1					37
36	4					38
44	2					39
18	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.
24	1					1
18	1					2
12	1	1				3
20	2					4
25	1					5
10	1					6
18	1					7
36	2					8
20	1					9
24	1					10
						11
						12
						13
						14
						15
24	3	1				16
						17
						18
	1					19
	1					20
	1					21
			Line Reactor	1	48	22
			Line Reactor	1	35	23
			Line Reactor	1	35	24
			Line Reactor	1	35	25
			Line Reactor	1	35	26
20	3	1				27
						28
						29
685	3					30
55	1					31
55	1					32
12	1					33
333	2	1				34
1	1					35
40	1					36
8	3	1				37
20	2					38
38	2					39
25	1	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.
240	2					1
50	2					2
		1				3
15	1					4
10	3	1				5
244	2					6
100	1					7
15	1					8
100	3	1				9
15	1					10
10	1					11
						12
						13
703	7					14
						15
						16
						17
						18
						19
						20
334						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

Schedule Page: 426.2 Line No.: 31 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.: 39 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.: 19 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.: 20 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.: 21 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.: 22 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.: 23 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.: 24 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.: 25 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.: 26 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.: 30 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.: 31 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.: 32 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: 426.7 Line No.: 14 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	04/15/2015	End of 2014/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 Expenses	IDACORP, INC.	417420	951,135
22			922000	74,887
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39				
40				
41				
42				

ANNUAL REPORT

IDAHO SUPPLEMENT TO FERC FORM 1

MULTI-STATE ELECTRIC COMPANIES

INDEX

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UTILITIES COMMISSION

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STATEMENT OF INCOME FOR THE YEAR

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

Line No.	Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	11	$ 1,219,568,337	$ 1,185,097,499
3	Operating Expenses			
4	Operation Expenses (401)	15	744,611,224	675,538,535
5	Maintenance Expenses (402)	15	64,952,478	64,415,077
6	Depreciation Expense (403)		120,300,338	116,783,035
7	Amort. & Depl. of Utility Plant (404-405)		6,687,969	7,248,578
8	Amort. of Utility Plant Acq. Adj. (406)			
9	Amort. of Property Losses, Unrecovered Plant and			
10	Accretion Expense (411)		296,254	308,258
11	Regulatory Study Costs (407)			
12	Amort. of Conversion Expenses (407)			
13	Regulatory Debits/Credits (407.3 & 407.4)		-	-
14	Taxes Other Than Income Taxes (408.1)	2	29,569,719	28,374,334
15	Income Taxes - Federal (409.1)	2	(7,055,229)	10,004,411
16	- Other (409.1)	2	6,624,230	5,361,984
17	Provision for Deferred Income Taxes (410.1 & 411.1) Net	2	17,355,209	53,612,675
18	Investment Tax Credit Adj. - Net (411.4)	2	39,767	(742,193)
19	(Less) Gains from Disp. of Utility Plant (411.6)			
20	Losses from Disp. of Utility Plant (411.7)			
21	(Less) Gains from Disposition of Allowances (411.8)			
22	Losses from Disposition of Allowances (411.9)			
23				
24	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 22)		983,381,958	960,904,694
25				
26				
27	Net Utility Operating Income (Enter Total of line 2 less 24)		$ 236,186,379	$ 224,192,804

TAXES ALLOCATED TO IDAHO

Kind of Tax	Taxes Charged During Year
Taxes Other Than Income Taxes:	
Labor Related:	
FICA	$ 13,407,613
FUTA	87,691
State Unemployment	671,527
Payroll Deduction & Loading	(14,166,830)
Total Labor Related	0
Property Taxes	25,524,590
Kilowatt-hour Tax	1,127,188
Licenses	4,686
Regulatory Commission Fees	2,688,423
Irrigation PIC	224,831
Canada Sales Tax	0
Total Taxes Other Than Income Taxes	29,569,719
Federal Income Taxes	(7,055,229)
State Income Taxes	6,624,230
Deferred Income Taxes	17,355,209
Investment Tax Credit Adjustment - Net	39,767
Total Taxes Allocated to Idaho	$ 46,533,696

NOTES AND ACCOUNTS RECEIVABLE

Summary for Balance Sheet

Show separately by footnote the total amount of notes and accounts receivable from directors, officers, and employees included in Notes Receivable (Account 141) and Other Accounts Receivable (Account 143)

Line No.	Accounts (a)	Balance Beginning of Year (b)	Balance End of Year (c)
1	Notes Receivable (Account 141)	$ 50,208	
2	Customer Accounts Receivable (Account 142)	100,221,798	85,040,915
3	Other Accounts Receivable (Account 143)	11,336,452	14,677,441
4	(Disclose any capital stock subscription received)		
5	Total	$ 111,608,458	$ 99,718,356
6			
7	Less: Accumulated Provision for Uncollectible		
8	Accounts-Cr. (Account 144)	2,501,686	4,650,829
9			
10	Total, Less Accumulated Provision for		
11	Uncollectible Accounts	$ 109,106,772	$ 95,067,527
12			
13			
14			
15			
16			
17			
18			
19			
20			

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

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

Line No.	Item (a)	Utility Customers (b)	Mdse, Jobbing & Contract Work (c)	Officers and Employees (d)	Other (e)	Total (f)
21	Balance Beg of Year:					
22	Uncollectible Accts	$ 2,332,388	$	$	$ (402,077)	$ 1,930,311
23						
24	Uncollectible Damage Claims	152,806			(9,160)	$ 143,646
25						
26	Uncollectibe Delivery Business Unit	16,492			2,560,380	$ 2,576,872
27						
28						
29						
30						
31						
32	Balance end of year	$ 2,501,686	$ -	$ -	$ 2,149,143	$ 4,650,829
33						

RECEIVABLES FROM ASSOCIATED COMPANIES (Accounts 145, 146)

1. Report particulars of notes and accounts receivable from associated companies at end of year.

2. Provide separate headings and totals for accounts 145, Notes Receivable from Associated Companies, and 146, Accounts Receivable from Associated Companies, in addition to a total for the combined accounts.

3. For notes receivable list each note separately and state purpose for which received. Show also in column (a) date of note, date of maturity and interest rate.

4. If any note was received in satisfaction of an open account, state the period covered by such open account.

5. Include in column (f) interest recorded as income during the year, including interest on accounts and notes held at any time during the year.

6. Give particulars of any notes pledged or discounted, also of any collateral held as guarantee of payment of any note or account.

Line No.	Particulars (a)	Balance Beginning of Year (b)	Totals for Year Debits (c)	Totals for Year Credits (d)	Balance End of Year (e)	Interest For Year (f)
1	Account 145:					
2						
3	IERCO............................		$ 2,053,198		$ 2,053,198	
4						
5						
6						
7						
8						
9						
10	Total Account 145................	-	2,053,198	-	2,053,198	
11						
12	Account 146:					
13						
14						
15						
16	IDACORP, Inc..................		$ 6,576,235	$ 6,576,235	$ -	
17						
18						
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
30						
31	Total Account 146..................	$ -	$ 6,576,235	$ 6,576,235	$ -	
32						

STATE OF IDAHO - TOTAL SYSTEM DATA

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

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

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

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

Line No.	Description of Property (a)	Original Cost of Related (b)	Date Journal Entry Approved (When Required) (c)	Acct 421.1 (d)	Acct 421.2 (e)
1	Gain on disposition of				
2	property:	$		$	$
3					
4					
5					
6					
7	Water Management Facility			$ 319	
8	Charges incurred in 2014 related to				
9	sale-disposal of land anticipaed in 2015.				
10	Boise Operations Center charges incurred			5,938	
11	in 2014 related to Sale-project anticipated				
12	to be completed in 2015.				
13					
14	Total gain	$ 0		$ 6,257	
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31	Total loss	$ 0			$ 0

STATE OF IDAHO - TOTAL SYSTEM DATA

PROFESSIONAL OR CONSULTATIVE SERVICES - ITEMS $10,000 AND OVER

Line No.	PAYEE (a)	SERVICE TYPE (b)	Amount (c)
1	ADECCO	Management Services	$ 14,822
2	AGREE TECHNOLOGIES AND SOLUTIO	Energy Efficiency Services	18,888
3	ALEMBA GROUP INC	IT Support Services	29,200
4	ANDERSON BANDUCCI PLLC	Legal Services	133,007
5	BAKER BOTTS LLP	Legal Services	137,128
6	BARCLAY CONSTRUCTION LLC	Legal Services	10,850
7	BARKER, ROSHOLT & SIMPSON LLP	Legal Services	473,831
8	BAYSWATER LLC	Legal Services	22,040
9	BERGLES LAW LLC	Legal Services	40,430
10	BETHKE LAW PLLC	Legal Services	13,395
11	BROWN AND CALDWELL	Legal Services	10,399
12	BULLARD SMITH JERNSTEDT WILSON	Legal Services	10,170
13	CASE FORENSICS CORPORATION	Management Services	12,942
14	DAVIS WRIGHT TREMAINE LLP	Legal Services	1,309,080
15	ELAM AND BURKE PA	Legal Services	45,729
16	EVANS KEANE	Legal Services	12,400
17	EVERGREEN CONSULTING GROUP, LL	Management Services	134,471
18	EVERGREEN ECONOMICS, INC.	Management Services	82,633
19	EXISTBI	Business Intelligence Support services	21,504
20	GIVENS PURSLEY LLP	Legal Services	306,279
21	GREENBERG TRAURIG LLP	Legal Services	14,360
22	HARDESTY, REBECCA	Real Estate	14,227
23	HDR ENGINEERING, INC	Engineering Services	31,584
24	HONEYWELL INTERNATIONAL INC	Management Services	953,914
25	INDUSTRIAL HYGIENE RESOURCES,	Management Services	22,856
26	ISS CORPORATE SERVICES, INC	Management Services	35,000
27	JOHNSON CONSULTING GROUP	Legal Services	21,850
28	KLARQUIST SPARKMAN LLP	Legal Services	13,685
29	MAINLINE INFORMATION SYSTEMS I	Management Services	51,600
30	MCDOWELL RACKNER & GIBSON PC	Legal Services	729,598
31	MIRANDE, MICHAEL	Legal Services	36,713
32	NETIQ	Data Center Management Services	39,600
33	NIELSEN GROUP INC, THE	Consulting Services	137,506
34	OXFORD GLOBAL RESOURCES INC	Management Services	60,620
35	PAINE HAMBLEN LLP	Legal Services	44,794
36	PARR BROWN GEE & LOVELESS INC	Legal Services	31,040
37	PERKINS COIE LLP	Legal Services	278,106
38	PROFESSIONAL TRAINING SYSTEMS	Training Consultants	11,381
39	RM ENERGY CONSULTING	Management Services	223,232
40	SCHWABE WILLIAMSON & WYATT	Legal Services	41,824
41	SCOTT & SCOTT LLP	Legal Services	22,120
42	STATE OF IDAHO	Management Services	100,000
43	STEPTOE & JOHNSON LLP	Legal Services	269,620
44	STOEL RIVES LLP	Legal Services	25,498
45			

STATE OF IDAHO - TOTAL SYSTEM DATA

PROFESSIONAL OR CONSULTATIVE SERVICES - ITEMS $10,000 AND OVER

Line No.	PAYEE (a)	SERVICE TYPE (b)	Amount (c)
46	TATA AMERICA INTERNATIONAL COR	Management Services	$ 24,320
47	TERRACON	Engineering Services	53,978
48	TETRA TECH MA INC	Environmental Services	54,950
49	THINK BIG SOLUTIONS INC	Management Services	46,020
50	TUERI LLC	Management Services	117,826
51	UNIVERSITY CORPORATION FOR	Cloud Seeding & Modeling Services	140,818
52	UNIVERSITY OF IDAHO	Management Services	538,495
53	VAN NESS FELDMAN	Legal Services	947,996
54	WILKINSON, BARKER, KNAUER LLP	Legal Services	13,125
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87			
	TOTAL		$ 7,987,455

PROFESSIONAL OR CONSULTATIVE SERVICES

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

Line No.	PAYEE	PREDOMINANT NATURE OF SERVICE	AMOUNT
1	ENGINEERING INCORPORATED	Enengeering Services	$ 5,145
2	FIRE CAUSE ANALYSIS	Fire Investigation Services	7,291
3	GYNII GILLIAM & ASSOCIATES	Management Services	6,153
4	JACKSON LEWIS PC	Legal Services	8,754
5	JONES AND SWARTZ PLLC	Legal Services	6,593
6	JONES GLEDHILL FUHRMAN GOURLEY	Legal Services	6,213
7	STEPHAN, KVANVIG, STONE & TRAI	Management Services	7,389
8	STRINDBERG & SCHOLNICK LLC	Legal Services	6,781
9	TOWERS WATSON PENNSYLVANIA INC	Energy Efficiency Services	8,900
10	WALDNER LAW OFFICES LLC	Legal Services	6,027
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45	**TOTAL**		$ 69,245

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

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

Line No.	Account (a)	Beginning of year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization	$ 5,459	
3	(302) Franchises and Consents	28,240,806	
4	(303) Miscellaneous Intangible Plant	30,634,533	
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	58,880,798	
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights		
9	(311) Structures and Improvements		
10	(312) Boiler Plant Equipment		
11	(313) Engines and Engine Driven Generators		
12	(314) Turbogenerator Units		
13	(315) Accessory Electric Equipment		
14	(316) Misc. Power Plant Equipment		
15	(317) Asset Retirement Costs for Steam Production	10,130,379	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	936,155,489	
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights		
19	(321) Structures and Improvements		
20	(322) Reactor Plant Equipment		
21	(323) Turbogenerator Units		
22	(324) Accessory Electric Equipment		
23	(325) Misc. Power Plant Equipment		
24	(326) Asset Retirement Costs for Nuclear Production		
25	TOTAL Nuclear Production Plant (Enter Total of lines 17 thru 24)		
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights		
28			
29	(332) Reservoirs, Dams, and Waterways		
30	(333) Water Wheels, Turbines, and Generators		
31	(334) Accessory Electric Equipment		
32	(335) Misc. Power Plant Equipment		
33	(336) Roads, Railroads, and Bridges		
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	707,937,550	
36	D. Other Production Plant		
37	(340) Land and Land Rights		
38	(341) Structures and Improvements		
39	(342) Fuel Holders, Products and Accessories		
40	(343) Prime Movers		
41	(344) Generators		
42	(345) Accessory Electric Equipment		
43	(346) Misc Power Plant Equipment		

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

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

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

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

Retirements (d)	Adjustments (e)	Transfers (f)	End of Year (g)		Line No.
					1
			$ 5,459	(301)	2
			28,048,263	(302)	3
			28,362,313	(303)	4
			56,416,036		5
					6
					7
				(310)	8
				(311)	9
				(312)	10
				(313)	11
				(314)	12
				(315)	13
				(316)	14
			6,611,529	(317)	15
			956,598,850		16
					17
				(320)	18
				(321)	19
				(322)	20
				(323)	21
				(324)	22
				(325)	23
				(326)	24
					25
					26
				(330)	27
				(331)	28
				(332)	29
				(333)	30
				(334)	31
				(335)	32
				(336)	33
				(337)	34
			731,577,803		35
					36
				(340)	37
				(341)	38
				(342)	39
				(343)	40
				(344)	41
				(345)	42
				(345)	43

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

Line No.	Account (a)	Balance at Beginning of year (b)	Additions (c)
44	(346) Misc. Power Plant Equipment		
45	TOTAL Other Production Plant (Enter Total of lines 37 thru 44)	$ 532,328,548	
46	TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 45)	2,176,421,587	
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	34,555,676	
49	(352) Structures and Improvements	67,099,513	
50	(353) Station Equipment	372,391,668	
51	(354) Towers and Fixtures	155,126,938	
52	(355) Poles and Fixtures	123,601,400	
53	(356) Overhead Conductors and Devices	180,079,653	
54	(357) Underground Conduit		
55	(358) Underground Conductors and Devices		
56	(359) Roads and Trails	373,698	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	933,228,546	
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	4,724,048	
61	(361) Structures and Improvements	31,686,059	
62	(362) Station Equipment	190,312,222	
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	217,558,714	
65	(365) Overhead Conductors and Devices	117,481,965	
66	(366) Underground Conduit	45,617,141	
67	(367) Underground Conductors and Devices	204,356,666	
68	(368) Line Transformers	452,677,796	
69	(369) Services	54,008,015	
70	(370) Meters	70,590,833	
71	(371) Installations on Customer Premises	2,672,425	
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	4,341,934	
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,396,027,818	
76	5. GENERAL PLANT		
77	(389) Land and Land Rights	15,871,405	
78	(390) Structures and Improvements	98,541,128	
79	(391) Office Furniture and Equipment	39,150,924	
80	(392) Transportation Equipment	64,833,977	
81	(393) Stores Equipment	1,827,216	
82	(394) Tools, Shop, and Garage Equipment	6,889,490	
83	(395) Laboratory Equipment	11,913,052	
84	(396) Power Operated Equipment	12,254,416	
85	(397) Communication Equipment	42,049,528	
86	(398) Miscellaneous Equipment	5,491,745	
87	SUBTOTAL (Enter Total of lines 77 thru 86)	298,822,881	
88	(399) Other Tangible Property		
89	(399.1) Asset Retirement Costs for General Plant		
90	TOTAL General Plant (Enter Total of lines 87, 88 and 89)	298,822,881	
91	TOTAL (Accounts 101 and 106)	4,863,381,630	
92	(102) Electric Plant Purchased		
93	(Less) (102) Electric Plant Sold		
94	(103) Experimental Plant Unclassified		
95			
96	TOTAL Electric Plant in Service	$ 4,863,381,630	

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
				(346)	44
			$ 530,535,722		45
			2,218,712,375		46
					47
			34,605,711	(350)	48
			69,637,541	(352)	49
			382,718,777	(353)	50
			161,019,362	(354)	51
			136,488,285	(355)	52
			187,968,276	(356)	53
				(357)	54
				(358)	55
			373,635	(359)	56
				(359.1)	57
			972,811,587		58
					59
			5,051,237	(360)	60
			32,116,160	(361)	61
			195,069,259	(362)	62
				(363)	63
			222,604,427	(364)	64
			119,358,951	(365)	65
			46,631,228	(366)	66
			215,537,454	(367)	67
			475,247,016	(368)	68
			55,003,907	(369)	69
			77,835,697	(370)	70
			2,688,508	(371)	71
				(372)	72
			4,299,302	(373)	73
				(374)	74
			1,451,443,147		75
					76
			15,870,623	(389)	77
			102,467,445	(390)	78
			43,942,561	(391)	79
			71,045,176	(392)	80
			1,853,706	(393)	81
			7,251,311	(394)	82
			12,112,184	(395)	83
			13,342,917	(396)	84
			51,491,365	(397)	85
			5,338,964	(398)	86
			324,716,252		87
				(399)	88
				(399.1)	89
			324,716,252		90
			5,024,099,396		91
				(102)	92
				(102)	93
				(371)	94
					95
			$ 5,024,099,396		96

ELECTRIC OPERATING REVENUES (Account 400)

1. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
2. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
3. If previous year (columns (c), (e) and (g), are not derived from previously reported figures, explain any inconsistencies in a footnote.

No.	(a)	OPERATING REVENUES Amount for Current Year (b)	Amount for Previous Year (c)
1	Sales of Electricity		
2	(440) Residential Sales	$ 481,950,250	$ 494,516,617
3	(442) Commercial and Industrial Sales		
4	Small (or Commercial)(See Instr. 4) (1)	436,588,320	419,209,017
5	Large (or Industrial)(See Instr. 4) (2)	167,602,922	151,362,762
6	(444) Public Street and Highway Lighting	3,976,711	3,686,439
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,090,118,203 *	1,068,774,834
11	(447) Sales for Resale - Opportunity....Non-Firm Only	73,741,042	52,068,941
12	TOTAL Sales of Electricity	1,163,859,245	1,120,843,775
13	(449) Provision for Rate Refunds	(18,363,613)	(18,719,941)
14	TOTAL Revenue Net of Provision for Refunds	1,145,495,632	1,102,123,834
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	3,696,703	3,490,381
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	22,576,034	23,276,587
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	47,799,967	56,206,697
22			
23			
24			
25	TOTAL Other Operating Revenues	74,072,705	82,973,665
26	TOTAL Electric Operating Revenues	$ 1,219,568,337	$ 1,185,097,499

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

ELECTRIC OPERATING REVENUES (Account 400) (Continued)

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

KILOWATT HOURS SOLD		AVERAGE NUMBER OF CUSTOMERS PER MONTH		
Amount for Current Year (d)	Amount for Previous Year (e)	Amount for Current Year (f)	Number for Previous Year (g)	Line No.
				1
4,784,072,514	5,167,474,041	411,689	405,542	2
				3
5,675,423,865	5,835,266,803	79,248	78,334	4
2,970,925,860	2,937,855,436	110	111	5
31,654,264	30,582,103	2,349	2,177	6
				7
				8
				9
13,462,076,503 **	13,971,178,383	493,396	486,164	10
2,121,897,891	1,609,051,066	N/A	N/A	11
15,583,974,394	15,580,229,449	493,396	486,164	12
				13

* Includes ($6,459,443) unbilled revenues.

** Includes (81,551,615) KWH relating to unbilled revenues.

Lines 11 through 21 are on an "allocated" basis.

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	$ 1,318,039	$ 1,460,217
5	(501) Fuel	149,242,737	153,204,613
6	(502) Steam Expenses	8,353,412	8,450,786
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,528,536	1,664,286
10	(506) Miscellaneous Steam Power Expenses	9,189,663	9,071,571
11	(507) Rents	507,911	333,534
12	(509) Allowances		
13	TOTAL Operation (Enter Total of lines 4 thru 12)	170,140,297	174,185,007
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	266,044	97,305
16	(511) Maintenance of Structures	678,123	610,766
17	(512) Maintenance of Boiler Plant	10,438,403	11,912,012
18	(513) Maintenance of Electric Plant	5,776,736	5,160,756
19	(514) Miscellaneous Steam Plant	5,558,967	4,348,643
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	22,718,272	22,129,481
21	TOTAL Power Production Expenses-Steam Power (Enter Total of lines 13 and :	192,858,570	196,314,488
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			
41	TOTAL Power Production Expenses-Nuclear Power (Enter Total of lines 33 and		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	5,456,838	5,777,960
45	(536) Water for Power	7,004,348	5,438,310
46	(537) Hydraulic Expenses	13,497,028	12,996,334
47	(538) Electric Expenses	1,464,659	1,371,316
48	(539) Miscellaneous Hydraulic Power Generation Expenses	5,488,290	4,649,652
49	(540) Rents	248,637	135,586
50	TOTAL Operation (Enter Total of lines 44 thru 49)	33,159,799	30,369,158

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	$ 116,975	$ 80,247
54	(542) Maintenance of Structures	1,328,245	1,366,715
55	(543) Maintenance of Reservoirs, Dams, and Waterways	350,696	1,099,550
56	(544) Maintenance of Electric Plant	2,181,187	2,504,756
57	(545) Maintenance of Miscellaneous Hydraulic Plant	2,445,769	2,878,078
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	6,422,872	7,929,346
59	TOTAL Power Production Expenses-Hydraulic Power (Enter Total of lines 50 anc	39,582,671	38,298,503
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	779,191	1,303,138
63	(547) Fuel	43,069,104	51,813,183
64	(548) Generation Expenses	3,440,496	3,279,215
65	(549) Miscellaneous Other Power Generation Expenses	866,982	560,834
66	(550) Rents	0	0
67	TOTAL Operation (Enter Total of lines 62 thru 66)	48,155,773	56,956,370
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	0	95
70	(552) Maintenance of Structures	361,955	288,496
71	(553) Maintenance of Generating and Electric Plant	82,752	125,473
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	1,332,131	1,181,596
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	1,776,838	1,595,660
74	TOTAL Power Production Expenses-Other Power (Enter Total of lines 67 and 73	49,932,611	58,552,030
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	226,605,619	205,462,329
77	(556) System Control and Load Dispatching	(1,189)	1,343,870
78	(557) Other Expenses	22,805,378	(37,062,415)
79	TOTAL Other Power Supply Expenses (Enter Total of lines 76 thru 78)	249,409,808	169,743,783
80	TOTAL Power Production Expenses (Enter Total of lines 21, 41, 59, 74, and 79).	531,783,660	462,908,805
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	3,847,645	3,408,752
84	(561) Load Dispatching	2,579,291	2,751,279
85	(562) Station Expenses	2,353,313	2,301,225
86	(563) Overhead Line Expenses	640,645	701,222
87	(564) Underground Line Expenses		
88	(565) Transmission of Electricity by Others	5,811,469	5,388,536
89	(566) Miscellaneous Transmission Expenses	17,494	47,470
90	(567) Rents	3,144,575	2,793,402
91	TOTAL Operation (Enter Total of lines 83 thru 90)	18,394,430	17,391,887
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	162,267	309,657
94	(569) Maintenance of Structures	994,016	721,848
95	(570) Maintenance of Station Equipment	3,544,467	3,456,623
96	(571) Maintenance of Overhead Lines	3,061,759	3,435,662
97	(572) Maintenance of Underground Lines		
98	(573) Maintenance of Miscellaneous Transmission Plant	1,525	581
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	7,764,033	7,924,372
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	26,158,464	25,316,258
101	3. DISTRIBUTION EXPENSES		
102	Operation		
103	(580) Operation Supervision and Engineering	3,856,280	3,980,894

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
104	3. DISTRIBUTION EXPENSES (Continued)		
105	(581) Load Dispatching	$ 3,500,477	$ 3,385,711
106	(582) Station Expenses	1,139,653	1,329,950
107	(583) Overhead Line Expenses	2,908,059	2,883,020
108	(584) Underground Line Expenses	2,489,099	2,366,316
109	(585) Street Lighting and Signal System Expenses	73,399	70,930
110	(586) Meter Expenses	4,276,734	4,267,367
111	(587) Customer Installations Expenses	640,974	620,736
112	(588) Miscellaneous Distribution Expenses	5,540,895	5,505,368
113	(589) Rents	446,160	350,339
114	TOTAL Operation (Enter Total of lines 103 thru 113)	24,871,729	24,760,632
115	Maintenance		
116	(590) Maintenance Supervision and Engineering	15,747	161,580
117	(591) Maintenance of Structures	0	0
118	(592) Maintenance of Station Equipment	3,814,699	3,691,123
119	(593) Maintenance of Overhead Lines	12,883,895	13,428,428
120	(594) Maintenance of Underground Lines	621,410	635,953
121	(595) Maintenance of Line Transformers	142,325	275,199
122	(596) Maintenance of Street Lighting and Signal Systems	507,517	511,473
123	(597) Maintenance of Meters	710,855	724,350
124	(598) Maintenance of Miscellaneous Distribution Plant	386,170	380,365
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	19,082,617	19,808,470
126	TOTAL Distribution Expenses (Enter Total of lines 114 and 125)	43,954,347	44,569,102
127	4. CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision	481,778	469,738
130	(902) Meter Reading Expenses	1,492,534	1,312,575
131	(903) Customer Records and Collection Expenses	16,030,097	13,547,108
132	(904) Uncollectible Accounts	6,316,859	5,486,585
133	(905) Miscellaneous Customer Accounts Expenses	90	258
134	TOTAL Customer Accounts Expenses (Enter Total of lines 129 thru 133)	24,321,358	20,816,263
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision	561,496	513,764
138	(908) Customer Assistance Expenses	32,298,865	41,266,485
139	(909) Informational and Instructional Expenses	361,011	255,050
140	(910) Miscellaneous Customer Service and Informational Expenses	658,759	555,685
141	TOTAL Cust. Service and Informational Expenses (Enter Total of lines 137 thru 14	33,880,131	42,590,984
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	69,850,602	66,097,448
152	(921) Office Supplies and Expenses	16,647,453	16,835,064
153	(Less) (922) Administrative Expenses Transferred-Credit	(26,023,220)	(25,698,427)

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
154	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
155	(923) Outside Services Employed	$ 4,492,073	$ 5,039,591
156	(924) Property Insurance	3,315,652	3,520,294
157	(925) Injuries and Damages	5,847,681	5,443,509
158	(926) Employee Pensions and Benefits	59,787,654	59,345,081
159	(927) Franchise Requirements	0	0
160	(928) Regulatory Commission Expenses	3,242,013	3,601,314
161	(929) Duplicate Charges-Cr		
162	(930.1) General Advertising Expenses	432,639	475,041
163	(930.2) Miscellaneous General Expenses	4,685,182	4,059,279
164	(931) Rents	168	6,257
165	TOTAL Operation (Enter Total of lines 151 thru 164)	142,277,897	138,724,451
166	Maintenance		
167	(935) Maintenance of General Plant	7,187,845	5,027,749
168	TOTAL Admin and General Expenses (Enter Total of lines 165-167)	149,465,742	143,752,200
169	TOTAL Elec Op and Maint Exp (Total of 80, 100, 126, 134, 141, 148, 168)	$ 809,563,702	$ 739,953,612

IDAHO ONLY

NUMBER OF ELECTRIC DEPARTMENT EMPLOYEES

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

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

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

1	Payroll Period Ended (Date)	December 31, 2014	December 31, 2013
2	Total Regular Full-Time Employees	2,011	2,010
3	Total Part-Time and Temporary Employees	20	18
4	Total Employees	2,031	2,028