e-FILING REPORT COVER SHEET

REPORT NAME: 2015 FERC Form 1 and Annual Report

COMPANY NAME: Idaho Power Company

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☒ No ☐ Yes

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

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

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

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

If Yes, enter docket number:

Key words:

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

☐ Corporate Analysis and Water Regulation

☐ Economic and Policy Analysis

☐ Electric and Natural Gas Revenue Requirements

☐ Electric Rates and Planning

☐ Natural Gas Rates and Planning

☐ Utility Safety, Reliability & Security

☐ Administrative Hearings Division

☐ Consumer Services Section

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

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

LISA D. NORDSTROM
Lead Counsel
lnordstrom@idahopower.com

April 18, 2016

Public Utility Commission of Oregon
Filing Center
201 High Street SE, Suite 100
P.O. Box 1088
Salem, Oregon 97301

Re: Idaho Power Company's 2015 Annual FERC Form 1 Report

Attention Filing Center:

As required by OAR 860-027-0070, Idaho Power Company herewith transmits for electronic filing its FERC Form 1 report and Oregon supplement for the year ending December 31, 2015. Also included is the IDACORP 2015 Annual Report.

If you have any questions, please contact Regulatory Analyst Kelley Noe at 208-388-5736 or knoe@idahopower.com.

Very truly yours,

Lisa D. Nordstrom

Lisa D. Nordstrom

LDN:kkt

Enclosures

THIS FILING IS	
Item 1: [X] 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 2015/Q4

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

IDENTIFICATION

01 Exact Legal Name of Respondent Idaho Power Company	02 Year/Period of Report End of 2015/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 1221 W Idaho St, P.O. Box 70 Boise, Id 83707-0070	
05 Name of Contact Person Ken Petersen	06 Title of Contact Person VP, Controller and CAO
07 Address of Contact Person *(Street, City, State, Zip Code)* 1221 W Idaho St, P.O. Box 70 Boise, Id 83707-0070	

08 Telephone of Contact Person, *Including Area Code* (208) 388-2761	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* 04/15/2016

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name Ken Petersen 02 Title Vice President, Controller & CAO	03 Signature Ken Petersen	04 Date Signed *(Mo, Da, Yr)* 04/15/2016

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

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/Q4

LIST OF SCHEDULES (Electric Utility)

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

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	N/A
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Regional Transmission Service Revenues (Account 457.1)	302	N/A
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310-311	
46	Electric Operation and Maintenance Expenses	320-323	
47	Purchased Power	326-327	
48	Transmission of Electricity for Others	328-330	
49	Transmission of Electricity by ISO/RTOs	331	N/A
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant	336-337	
53	Regulatory Commission Expenses	350-351	
54	Research, Development and Demonstration Activities	352-353	
55	Distribution of Salaries and Wages	354-355	
56	Common Utility Plant and Expenses	356	N/A
57	Amounts included in ISO/RTO Settlement Statements	397	N/A
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	N/A
61	Electric Energy Account	401	
62	Monthly Peaks and Output	401	
63	Steam Electric Generating Plant Statistics	402-403	
64	Hydroelectric Generating Plant Statistics	406-407	
65	Pumped Storage Generating Plant Statistics	408-409	N/A
66	Generating Plant Statistics Pages	410-411	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
67	Transmission 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	04/15/2016	End of 2015/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 Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report *(Mo, Da, Yr)* 04/15/2016	Year/Period of Report End of 2015/Q4

CONTROL OVER RESPONDENT

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

Idaho Power Company is a subsidiary of IDACORP, INC

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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	04/15/2016	End of 2015/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	675,000
3			
4	Executive Vice President & Chief Operating Officer	Dan Minor	460,000
5			
6	Senior Vice President & General Counsel	Rex Blackburn	350,000
7			
8	Senior Vice President, CFO & Treasurer	Steven Keen	345,000
9			
10	Senior Vice President, Power Supply	Lisa Grow	320,000
11			
12	Vice President, Public Affairs	Jeffrey Malmen	260,000
13			
14	Senior Vice President, Customer Operations	Vern Porter	260,000
15			
16	Vice President, Human Resources, Admin Services, & CIO	Lonnie Krawl	250,000
17			
18	Vice President, & Chief Risk Officer	Lori Smith	242,000
19			
20	Vice President, Corporate Controller & CAO	Ken Petersen	235,000
21			
22	Vice President of Regulatory Affairs	Gregory Said	217,000
23			
24	Corporate Secretary	Patrick Harrington	188,000
25			
26	Senior Vice President, Customer Operations	Warren Kline (1)	159,750
27			
28	Vice President, Human Resources & Corporate Services	Luci McDonald (2)	127,307
29			
30	(1) Retirement effective 6/30/15. Base shows YTD wages		
31	(2) Retirement effective 5/31/15. Base shows YTD wages		
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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	04/15/2016	End of 2015/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	10446 E. Palo Brea Dr., Scottsdale, Arizona 85262
3		
4	Christine King***	8527 East Old Field Rd
5		Scottsdale, Arizona 85266
6		
7	Thomas Carlile	2719 North Woodview place, Boise Idaho 83702
8		
9	Jan B. Packwood (1)	900 W. Bogus View Drive, Eagle, Idaho 83616
10		
11	Darrel T. Anderson President & CEO, ** ***	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 (2)	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 (3)	1504 Warm Springs Avenue
22		Boise, Idaho 83712
23		
24	Richard Dahl ***	60 Laiki Pl.
25		Kailua, HawaiI 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	Richard J. Navarro (4)	1256 E. Candleridge Ct., Boise, Idaho 83712
34		
35	(1) Retired on May 21, 2015	
36	(2) Retired on May 21, 2015	
37	(3) Retired on May 21, 2015	
38	(4) Appointed to Board February 10, 2015	
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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	04/15/2016	End of 2015/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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Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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	201508285322	08/28/2015	ER09-1641-000	Idaho Power Company	FERC Electirc Tariff
2				2015 Annual	
3				Informational Filling	
4				under ER-09-1641-000	
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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) 04/15/2016	Year/Period of Report End of 2015/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
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

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

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 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. To enhance the abilities of Idaho Power and PacifiCorp to serve their respective customers, on October 24, 2014, Idaho Power and PacifiCorp executed a Joint Ownership and Operating Agreement (Joint Operating Agreement) applicable to certain transmission-related equipment to be exchanged by Idaho Power and PacifiCorp. The exchange was made pursuant to the terms of a Joint Purchase and Sale Agreement, also dated October 24, 2014, between Idaho Power and PacifiCorp, under which each party agreed to transfer to the other specified transmission-related equipment with an estimated year-end 2014 net book value of approximately $43 million, subject to true-up as of the closing date. The transaction also provided for the termination and amendment of a number of legacy long-term agreements related to the ownership and operation of jointly-owned facilities and transmission services between Idaho Power and PacifiCorp. Idaho Power received FERC approval of the transaction on June 17, 2015 (*See: Idaho Power Co., PacifiCorp*, 151 FERC ¶ 61,233 (2015). FERC Docket No. EC15-54-000). As a condition of approval, FERC required Idaho Power and PacifiCorp to submit final accounting for the transaction within six months of the transaction's closing. (See: *Idaho Power Co., PacifiCorp*, Order Authorizing Acquisition and Disposition of Jurisdictional Facilities, 151 FERC ¶ 61,233 (2015). The transaction closed on October 30, 2015 and final accounting will be submitted to FERC on or before April 30, 2016.

4. None

5. None

6. Disclosed in Financial Statement footnotes, see pages 123.13 to 123.14

7. None

8. Effective 01/03/2015 a 3.0% general wage adjustment was implemented

9. Disclosed in Financial Statement footnotes, see pages 123.18 to 123.19

10. All of the below related person transactions were reviewed and approved by the Idaho Power Board of Directors and the Corporate Governance and Nominating Committee.

- Steven R. Keen, Idaho Power's Senior Vice President, Chief Financial Officer and Treasurer is the brother of J. LaMont Keen, a member of Idaho Power's board of directors.
- Rex Blackburn is the Sr. Vice President and General Counsel of Idaho power. His brother-in-law, Gary Betts, is also an employee of Idaho Power.
- Patrick A. Harrington is the Corporate Secretary of Idaho Power. His brother, Jamie Harrington, is also an employee of Idaho Power.
- Lori D. Smith was the Vice President and Chief Risk Officer of Idaho Power in 2015. Her husband, Matt Smith, was also an employee of Idaho Power in 2015.

11. None

12. None

13. Director Changes in 2015:
- Richard J. Navarro appointed to Board 2/11/2015
- Jan B. Packwood, Joan H. Smith, and Thomas J. Wilford retired from the Board 5/21/2015

Officer Changes in 2015:
- Warren Kline retired as Sr. Vice President- Customer Operations effective

6/30/2015
- Luci K. McDonald retired as Vice President- Human Resources and Corporate Services effective 5/31/2015
- N. Vern Porter title changed from "Vice President" to "Sr. Vice President of Customer Operations" effective 4/1/2015
- Lonnie G. Krawl title changed from "Vice President and Chief Information Officer" to "Vice President of Human Resources, Administrative Services and Chief Information Officer" effective 4/1/2015

Officer changes approved in 2015 but not effective until 2016:
- Daniel B. Minor title change from "Executive Vice President and Chief Operating Officer" to "Executive Vice President"
- Lisa A. Grow title change from "Sr. Vice President- Power Supply to "Sr. Vice President of Operations"
- N. Vern Porter title change from "Sr. Vice President of Customer Operations" to "Vice President of Customer Operations"
- Lonnie G. Krawl title change from "Vice President and Chief Information Officer" to "Sr. Vice President of Administrative Services and Chief Information Officer"
- Tessia R. Park new appointment to "Vice President of Power Supply"
- Jeffrey S. Glenn new appointment to "Vice President of Information Technology"

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

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	5,492,554,138	5,255,302,762
3	Construction Work in Progress (107)	200-201	396,931,372	401,929,509
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		5,889,485,510	5,657,232,271
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	2,097,432,010	2,021,073,827
6	Net Utility Plant (Enter Total of line 4 less 5)		3,792,053,500	3,636,158,444
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)		3,792,053,500	3,636,158,444
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	1,555,480
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	84,137,401	83,477,460
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)		416	647
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		24,560,677	45,082,335
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		126,480	63,323
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		110,380,454	130,179,245
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		100,745,383	46,581,578
36	Special Deposits (132-134)		1,637,072	1,079,260
37	Working Fund (135)		10,600	13,600
38	Temporary Cash Investments (136)		10,000,000	100,000
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		75,650,719	85,040,915
41	Other Accounts Receivable (143)		23,486,155	14,677,441
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		1,355,042	4,650,829
43	Notes Receivable from Associated Companies (145)		1,156,202	2,053,197
44	Accounts Receivable from Assoc. Companies (146)		0	0
45	Fuel Stock (151)	227	61,818,257	55,170,482
46	Fuel Stock Expenses Undistributed (152)	227	0	599
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	52,445,228	50,305,479
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	0	0
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	0	0

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	4,478,320	5,098,760
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		17,845,551	18,355,589
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)		65,804,608	56,269,642
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		405,239	634,183
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		126,480	63,323
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)		414,001,812	330,666,573
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		16,539,636	15,815,910
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	1,355,572,128	1,237,823,724
73	Prelim. Survey and Investigation Charges (Electric) (183)		1,177	873,939
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)		1,650,910	1,053,324
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	66,701,295	45,564,713
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)		29,731,072	12,799,888
82	Accumulated Deferred Income Taxes (190)	234	270,188,395	289,103,584
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,740,384,613	1,603,035,082
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		6,056,820,379	5,700,039,344

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	end of 2015/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	1,045,751,377	952,335,875
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	81,674,308	81,014,366
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)	-21,275,735	-24,157,999
16	Total Proprietary Capital (lines 2 through 15)		1,914,187,490	1,817,229,782
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,725,460,000	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	22,012,273	23,075,909
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		4,458,587	3,034,022
24	Total Long-Term Debt (lines 18 through 23)		1,743,013,686	1,615,501,887
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)		1,873,877	1,994,972
29	Accumulated Provision for Pensions and Benefits (228.3)		394,131,877	403,474,921
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	3,865,254
31	Accumulated Provision for Rate Refunds (229)		87,689,554	72,974,757
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)		26,152,620	21,930,049
35	Total Other Noncurrent Liabilities (lines 26 through 34)		509,847,928	504,239,953
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		119,524,930	113,979,552
39	Notes Payable to Associated Companies (233)		0	0
40	Accounts Payable to Associated Companies (234)		1,058,872	2,027,220
41	Customer Deposits (235)		4,731,724	1,568,822
42	Taxes Accrued (236)	262-263	5,192,418	-10,635,253
43	Interest Accrued (237)		22,387,590	22,670,165
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

Name of Respondent Idaho Power Company	This Report is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report *(mo, da, yr)* 04/15/2016	Year/Period of Report end of 2015/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)		1,921,386	2,599,099
48	Miscellaneous Current and Accrued Liabilities (242)		53,364,600	40,889,480
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		4,972,600	3,960,704
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)		213,154,120	177,059,789
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		4,678,929	3,303,553
57	Accumulated Deferred Investment Tax Credits (255)	266-267	79,654,930	79,162,831
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	11,757,998	11,635,642
60	Other Regulatory Liabilities (254)	278	67,711,655	64,843,269
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)		1,349,907,020	1,248,630,361
64	Accum. Deferred Income Taxes-Other (283)		162,906,623	178,432,277
65	Total Deferred Credits (lines 56 through 64)		1,676,617,155	1,586,007,933
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		6,056,820,379	5,700,039,344

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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	1,266,201,447	1,277,640,977		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	731,125,349	780,281,536		
5	Maintenance Expenses (402)	320-323	69,399,154	68,283,304		
6	Depreciation Expense (403)	336-337	130,382,128	125,245,540		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	549,017	495,029		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	7,095,926	7,172,382		
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)		82,611	73,650		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	32,808,301	31,748,230		
15	Income Taxes - Federal (409.1)	262-263	12,593,365	-7,413,733		
16	- Other (409.1)	262-263	5,986,110	6,908,583		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	86,269,807	152,963,217		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	58,085,989	134,837,097		
19	Investment Tax Credit Adj. - Net (411.4)	266	492,099	41,541		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		97,422	186,382		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		232,049	309,716		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,018,832,505	1,031,085,516		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		247,368,942	246,555,461		

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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
1,266,201,447	1,277,640,977					2
						3
731,125,349	780,281,536					4
69,399,154	68,283,304					5
130,382,128	125,245,540					6
549,017	495,029					7
7,095,926	7,172,382					8
						9
						10
						11
82,611	73,650					12
						13
32,808,301	31,748,230					14
12,593,365	-7,413,733					15
5,986,110	6,908,583					16
86,269,807	152,963,217					17
58,085,989	134,837,097					18
492,099	41,541					19
						20
						21
97,422	186,382					22
						23
232,049	309,716					24
1,018,832,505	1,031,085,516					25
247,368,942	246,555,461					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		247,368,942	246,555,461		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		1,304,085	1,009,910		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		1,485,862	1,136,669		
33	Revenues From Nonutility Operations (417)		33,733	37,547		
34	(Less) Expenses of Nonutility Operations (417.1)		10,586	22,828		
35	Nonoperating Rental Income (418)		-791	-527		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	6,659,942	7,092,887		
37	Interest and Dividend Income (419)		3,039,556	2,704,620		
38	Allowance for Other Funds Used During Construction (419.1)		21,785,246	17,930,898		
39	Miscellaneous Nonoperating Income (421)		2,365,842	2,453,947		
40	Gain on Disposition of Property (421.1)		-20	-4,240		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		33,691,145	30,065,545		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)			2,156		
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		750,960	747,094		
46	Life Insurance (426.2)		-1,738,804	-1,164,064		
47	Penalties (426.3)		48,305	27,106		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,477,633	1,561,921		
49	Other Deductions (426.5)		9,937,000	8,332,431		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		10,475,094	9,506,644		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	21,055	24,797		
53	Income Taxes-Federal (409.2)	262-263	353,061	-914,126		
54	Income Taxes-Other (409.2)	262-263	69,362	-41,215		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	5,911,613	1,085,673		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	8,478,300	2,008,392		
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)		-2,123,209	-1,853,263		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		25,339,260	22,412,164		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		83,055,805	80,561,920		
63	Amort. of Debt Disc. and Expense (428)		1,556,825	1,610,773		
64	Amortization of Loss on Reaquired Debt (428.1)		1,521,812	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)		6,859	10,524		
68	Other Interest Expense (431)		5,627,193	4,800,939		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		10,043,775	8,464,109		
70	Net Interest Charges (Total of lines 62 thru 69)		81,724,719	79,580,632		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		190,983,483	189,386,993		
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)		190,983,483	189,386,993		

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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	04/15/2016	End of 2015/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		939,062,769	836,965,502
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)		184,323,541	182,294,106
17	Appropriations of Retained Earnings (Acct. 436)			
18				(6,613,580)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			(6,613,580)
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			-96,908,039	(88,583,259)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-96,908,039	(88,583,259)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		6,000,000	15,000,000
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,032,478,271	939,062,769
	APPROPRIATED RETAINED EARNINGS (Account 215)			

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
39				
40				
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		13,273,106	13,273,106
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		13,273,106	13,273,106
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		1,045,751,377	952,335,875
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		81,014,366	88,921,479
50	Equity in Earnings for Year (Credit) (Account 418.1)		6,659,942	7,092,887
51	(Less) Dividends Received (Debit)		6,000,000	15,000,000
52				
53	Balance-End of Year (Total lines 49 thru 52)		81,674,308	81,014,366

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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)	190,983,483	189,386,993
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	130,382,128	125,245,540
5	Amortization of (detail in footnote):	11,590,185	11,250,901
6			
7			
8	Deferred Income Taxes (Net)	25,793,350	17,218,276
9	Investment Tax Credit Adjustment (Net)	315,879	26,665
10	Net (Increase) Decrease in Receivables	3,988,719	22,570,540
11	Net (Increase) Decrease in Inventory	-8,079,325	-15,385,702
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	17,501,301	-18,687,818
14	Net (Increase) Decrease in Other Regulatory Assets	1,465,215	16,794,041
15	Net Increase (Decrease) in Other Regulatory Liabilities	12,233,990	15,341,861
16	(Less) Allowance for Other Funds Used During Construction	21,785,246	17,930,898
17	(Less) Undistributed Earnings from Subsidiary Companies	659,942	-7,907,113
18	Other (provide details in footnote):	-18,199,440	4,789,855
19			
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	345,530,297	358,527,367
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-315,753,782	-291,841,495
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	-21,785,246	-17,930,898
31	Other (provide details in footnote):	13,456,680	3,551,443
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-280,511,856	-270,359,154
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	896,996	-15,317,379
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)	-44,105,638	-8,000,000
45	Proceeds from Sales of Investment Securities (a)	34,243,180	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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
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):	-1,374,426	4,906,085
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-290,851,744	-288,720,240
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	250,000,000	
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)	250,000,000	
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-121,063,637	-1,063,636
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):	-22,646,072	
77			
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-96,908,039	-88,583,259
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	9,382,252	-89,646,895
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	64,060,805	-19,839,768
87			
88	Cash and Cash Equivalents at Beginning of Period	46,695,178	66,534,946
89			
90	Cash and Cash Equivalents at End of period	110,755,983	46,695,178

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

Amortization	
Plant	7,095,926
Unamortized debt expense	3,090,337
Unamortized discount	290,435
Water rights	1,042,009
Other	71,478
	11,590,185

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

Cash paid during the period for:	
Income taxes	3,547,630
Interest (net of amount capitalized)	79,225,751

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

Cash Flow from Operating Activities (Other)	
Pension and postretirement benefit plan expense	30,185,123
Contributions to pension and postretirement benefit plans	(42,821,074)
Unbilled revenues	(7,691,484)
Prepayments	922,055
Company owned life insurance	5,327,068
Deposits from third parties	5,309,053
Other	(9,430,181)
	(18,199,440)

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

Non-cash investing activities:	
Additions to PP&E in accounts payable	23,839,605

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

Other Cash Flows from Plant	
Sale of utility property	71,180
Payments received from joint funding partners	11,377,277
Sale of emission allowances and renewable energy certificates	2,008,223
	13,456,680

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

Other Investing Cash Flows	
EDC plan investments	32,308
Feasibility study costs	(1,406,964)
Miscellaneous other investing activities	230
	(1,374,426)

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

Other Financing Cash Flows	
Make-whole premium on retirement of long-term debt	(17,871,600)
Debt issuance costs	(3,059,472)
Discount on debt issuance	(1,715,000)
	(22,646,072)

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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				(16,553,375)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				1,728,379
3	Preceding Quarter/Year to Date Changes in Fair Value				(9,333,003)
4	Total (lines 2 and 3)				(7,604,624)
5	Balance of Account 219 at End of Preceding Quarter/Year				(24,157,999)
6	Balance of Account 219 at Beginning of Current Year				(24,157,999)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				2,667,521
8	Current Quarter/Year to Date Changes in Fair Value				214,743
9	Total (lines 7 and 8)				2,882,264
10	Balance of Account 219 at End of Current Quarter/Year				(21,275,735)

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			(16,553,375)		
2			1,728,379		
3			(9,333,003)		
4			(7,604,624)	189,386,993	181,782,369
5			(24,157,999)		
6			(24,157,999)		
7			2,667,521		
8			214,743		
9			2,882,264	190,983,483	193,865,747
10			(21,275,735)		

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/Q4

NOTES TO FINANCIAL STATEMENTS

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

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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, (7) accrued taxes and (8) debt issue costs.

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 or accrued 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.

Other receivables, primarily notes receivable from business transactions, 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, 2015 and 2014. 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. In addition, regulatory mechanisms in place in Idaho and Oregon affect the reported amount of revenue. See Note 3 for additional discussion of certain of the following mechanisms:

- energy efficiency riders to fund energy efficiency program expenditures. Expenditures funded through the rider are reported as an operating expense with an equal amount of revenues recorded in other revenues;
- a fixed cost adjustment mechanism that results in recording additional or reduced revenue based on the allowed and actual fixed costs recovered through current rates;
- a sharing mechanism providing for refunds to customers for earnings above stated returns on equity in Idaho;
- franchise fees and similar taxes related to energy consumption. None of these collections are reported on the income statement; and
- collection in base rates of 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 deferred 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 2015 and 2014.

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. 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 long-lived assets in 2015 or 2014.

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 7.6 percent for 2015 and 7.7 percent for 2014.

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 amortized over the terms of the respective debt issues. Losses on reacquired debt and associated costs are amortized over the life of the associated replacement debt, as allowed under regulatory accounting.

Supplemental Cash Flows Information

In 2015, Idaho Power executed an agreement to exchange property with another electric utility. Under the terms of the agreement, each party transferred to the other transmission-related equipment with a book value of approximately $44 million. Idaho Power received an immaterial amount of cash, representing the difference in the book value of the assets exchanged.

Also in 2015, Idaho Power executed a long-term service agreement and transferred to the service provider approximately $22 million of spare parts in partial exchange for future services. No cash was exchanged in the 2015 transfer transaction.

Recently Issued Accounting Pronouncements

In May 2014, the FASB issued 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, 2017, including interim periods, with early adoption permitted one year earlier. 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. Idaho Power is currently evaluating the impact of ASU 2014-09 on its financial statements.

In February 2015, the FASB issued ASU 2015-02, *Consolidation (Topic 810) - Amendments to the Consolidation Analysis,* which revises the consolidation model that reporting entities use when determining what entities are to be consolidated. The amendments focus on limited partnerships and similar legal entities, and are effective for interim and annual reporting periods beginning after December 31, 2015. Idaho Power does not believe the impact of ASU 2015-02 on its financial statements will be significant.

In January 2016, the FASB issued ASU 2016-01, *Financial Instruments—Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities,* which revises the accounting related to the classification and measurement of investments in equity securities and the presentation of certain fair value changes for financial liabilities measured at fair value. It also amends certain disclosure requirements associated with the fair value of financial instruments. The new standard is effective for fiscal years beginning after December 15, 2017, including interim periods. Idaho Power is currently evaluating the impact of ASU 2016-01 on its financial statements.

Subsequent Events

Management has evaluated the impact of events occurring after December 31, 2015 up to February 18, 2016, 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, 2016. 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:

	2015	2014
Federal income tax expense at 35% statutory rate	$ 82,633	$ 71,810
Change in taxes resulting from:		
Equity earnings of subsidiary companies	(2,331)	(2,483)
AFUDC	(11,140)	(9,238)
Capitalized interest	2,693	2,278
Investment tax credits	(2,963)	(3,002)
Removal costs	(4,807)	(3,656)
Capitalized overhead costs	(8,750)	(8,750)
Capitalized repair costs	(28,700)	(26,250)
Bond redemption costs	(6,459)	—
Tax method change – capitalized repairs	—	(24,516)
State income taxes, net of federal benefit	7,503	5,334
Depreciation	17,149	16,040
Other, net	283	(1,783)
Total income tax expense	$ 45,111	$ 15,784
Effective tax rate	19.10%	7.70%

The items comprising income tax expense are as follows:

	2015	2014
	(thousands of dollars)	
Income taxes current:		
Federal	$ 12,946	$ (8,328)
State	6,056	6,867
Total	19,002	(1,461)
Income taxes deferred:		
Federal	28,103	23,624
State	(2,486)	(6,421)
Total	25,617	17,203
Investment tax credits:		
Deferred	3,455	3,044
Restored	(2,963)	(3,002)
Total	492	42
Total income tax expense	$ 45,111	$ 15,784

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

	2015	2014
	(thousands of dollars)	
Deferred tax assets:		
Regulatory liabilities	$ 51,131	$ 55,490
Deferred compensation	27,489	25,240
Deferred revenue	34,282	28,529
Tax credits	30,223	26,768
Retirement benefits	126,885	132,571
Other	10,745	14,553
Total	280,755	283,151
Deferred tax liabilities:		
Property, plant and equipment	474,879	451,118
Regulatory assets	875,028	802,188
Power cost adjustments	18,489	23,192
Retirement benefits	126,090	122,360
Other	28,895	22,252
Total	1,523,381	1,421,110
Net deferred tax liabilities	$ 1,242,626	$ 1,137,959

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 they have no material income tax uncertainties for 2015 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 their major tax jurisdictions - U.S. federal and the State of Idaho. The open tax years for examination are 2015 for federal and 2012-2015 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 2015, the IRS completed its examination of IDACORP's 2014 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 was pursuant to Revenue Procedure 2013-24 and brought 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 incorporated provisions of the final tangible property regulations issued by the U.S. Treasury Department and IRS in 2013 that addressed the deduction or capitalization of expenditures related to tangible property. Following the automatic consent procedures provided for in the Revenue Procedure, Idaho Power adopted this method with the filing of IDACORP’s 2014 consolidated federal income tax return in September 2015. The IRS approved the method change prior to the filing of the return as part of IDACORP’s 2014 CAP examination.

In 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 of 2014. 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.

3. REGULATORY MATTERS

Idaho Power's financial statements reflect the effects of the different ratemaking principles followed by the jurisdictions regulating Idaho Power. Included below is a summary of Idaho Power's regulatory assets and liabilities, as well as a discussion of notable regulatory matters.

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):

Description	Remaining Amortization Period	As of December 31, 2015 Earning a Return(1)	Not Earning a Return	Total as of December 31, 2015	2014
Regulatory Assets:					
Income taxes		$	$ 875,027	$ 875,027	$ 802,188
Unfunded postretirement benefits(2)		—	251,762	251,762	264,548
Pension expense deferrals		62,642	23,148	85,790	63,644
Energy efficiency program costs(3)		4,482	—	4,482	4,690
Power supply costs(4)	Varies	47,220	—	47,220	59,189
Fixed cost adjustment(4)	2016-2017	36,820	—	36,820	23,737
Asset retirement obligations(5)		—	14,410	14,410	17,309
Mark-to-market liabilities(6)		—	4,973	4,973	3,961
Long-term service agreement(7)	2043	18,592	11,633	30,225	—
Other	2016-2021	1,096	3,704	4,800	3,121
Total		$ 170,852	$ 1,183,573	$ 1,355,509	$ 1,242,387
Regulatory Liabilities:					
Income taxes		$	$ 51,131	$ 51,131	$ 55,490
Energy efficiency program costs(3)		6,554	—	6,554	—
Power supply costs(4)		—	—	—	1
Settlement agreement sharing mechanism(4)	2016-2017	3,159	—	3,159	7,999
Mark-to-market assets(6)		—	405	405	1,880
Other		5,219	1,180	6,399	4,036
Total		$ 14,932	$ 52,716	$ 67,648	$ 69,406

(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) The 2015 energy efficiency asset represents the Oregon jurisdiction balance and the liability represents the Idaho jurisdiction balance. Both jurisdictions' balances were assets at December 31, 2014.

(4) These items are discussed in more detail in this Note 3.

(5) Asset retirement obligations are discussed in Note 12.

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

(7) A portion not earning a return as of December 31, 2015 will be eligible to earn a return as of January 1, 2018.

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 net power supply costs (primarily fuel and purchased power less off-system sales) against net power supply costs being recovered. Under the PCA mechanisms, certain differences between actual net power supply costs incurred by Idaho Power and the costs are recorded as a deferred charge or credit on the balance sheets for future recovery or refund. 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 sales-based adjustment intended to ensure that power supply expense recovery resulting solely from sales changes does not distort the results of the mechanism.

The table below summarizes the three 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, 2015	$ (11.6)	The net decrease in Idaho PCA rates included the application of (a) a customer rate credit of $8.0 million for sharing of revenues with customers for the year 2014 under the terms of the December 2011 settlement stipulation, and (b) $4.0 million of surplus Idaho energy efficiency rider funds.
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. The shifting of base net power supply costs is discussed in more detail below.

In March 2014, the IPUC issued an order approving Idaho Power's application 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 became effective June 1, 2014. Approval of the order removed the Idaho-jurisdictional portion of those expenses (approximately $99 million) from collection via the Idaho PCA mechanism and instead results in collecting that portion through base rates.

In July 2014, the IPUC opened a docket pursuant to which Idaho Power, the IPUC Staff, and other interested parties further evaluated Idaho Power's application of the true-up component of the PCA mechanism and whether a deferral balance adjustment was appropriate. While the IPUC's docket was closed in August 2014 with no adjustment to the PCA true-up revenue amount, Idaho Power subsequently met with the IPUC Staff to explore approaches to increasing the accuracy of the actual cost recovery under the PCA mechanism. In May 2015, the IPUC approved a settlement stipulation that resulted in the replacement of the existing load-based adjustment used for determining the power cost deferrals under the PCA mechanism with a similar sales-based adjustment. The sales-based adjustment functions in the same manner as the previous load-based adjustment but measures deviations between Idaho-specific test year sales and actual Idaho sales rather than deviations between test year loads and actual loads. The approved settlement stipulation implemented the new methodology as of January 1, 2015.

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 2015, and 2014, are summarized in the table that follows:

Year and Mechanism	APCU or PCAM Adjustment
2015 PCAM	Actual net power supply costs were within the deadband, resulting in no deferral.
2015 APCU	A rate decrease of $0.7 million annually took effect June 1, 2015.
2014 PCAM	Actual net power supply costs were within the deadband, resulting in no deferral.
2014 APCU	A rate increase of $0.4 million annually took effect June 1, 2014.

Notable Idaho Regulatory Matters

Idaho Base Rate Changes: Idaho base rates were most recently established in 2012, and adjusted in 2014. 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. In June 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 became effective June 1, 2014.

December 2011 Idaho Settlement Stipulation: In December 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 was less than 9.5 percent, then Idaho Power may amortize up to a total of $45 million of additional accumulated deferred investment tax credits (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 exceeded 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 exceeded 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 each of 2012, 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 2014 for sharing with customers under the December 2011 Idaho regulatory settlement stipulation was $8 million as refunds to customers and $16.7 million as pre-tax charges to pension expenses.

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 expense deferral regulatory asset (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.

Idaho Power recorded no additional ADITC amortization and a $3.2 million provision against current revenue for sharing with customers for 2015 under the October 2014 Idaho settlement stipulation, as its Idaho ROE for 2015 was above 10.0 percent.

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 authorized fixed-cost recovery amount and the actual fixed costs recovered by Idaho Power during the year. The annual change in 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 three FCA years:

FCA Year	Period Rates in Effect	Annual Amount (in millions)
2014	June 1, 2015-May 31, 2016	$16.9
2013	June 1, 2014-May 31, 2015	$14.9
2012	June 1, 2013-May 31, 2014	$8.9

In July 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 (including weather-normalization, customer count methodology, rate adjustment cap, and cross-subsidization issues) and whether the FCA is effectively removing Idaho Power's disincentive to aggressively pursue energy efficiency programs. In May 2015, the IPUC approved a settlement stipulation that modified the FCA mechanism by replacing weather-normalized billed sales with actual billed sales in the calculation of the FCA, applicable for the entirety of calendar year 2015 and thereafter, and reflected in FCA charges effective June 1, 2016.

Notable Oregon Regulatory Matters

Oregon Base Rate Changes: Oregon base rates were most recently established in a general rate case in 2012. In February 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, in September 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

Idaho Power uses 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, 2015 to September 30, 2016	$	23.43
October 1, 2014 to September 30, 2015	$	22.48
October 1, 2013 to September 30, 2014	$	22.80

Idaho Power's current OATT rate is based on a net annual transmission revenue requirement of $121.3 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):

	2015	2014
First mortgage bonds:		
6.025% Series due 2018	$ —	$ 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
3.65% Series Due 2045	250,000	—
Total first mortgage bonds	1,555,000	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	2,127	3,191
Unamortized discounts	(4,459)	(3,034)
Total Idaho Power outstanding debt(2)	$ 1,743,013	$ 1,615,502

(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, 2015 to $1.721 billion.
(2) At December 31, 2015 and 2014, the overall effective cost of Idaho Power's outstanding debt was 4.96 percent and 5.19 percent, respectively.

At December 31, 2015, the maturities for the aggregate amount of Idaho Power's long-term debt outstanding were as follows (in thousands of dollars):

2016	2017	2018	2019	2020	Thereafter
$ 1,064	$ 1,064	$ —	$ 100,000	$ 230,000	$ 1,415,344

Long-Term Debt Issuances, Maturities, and Availability

On March 6, 2015, Idaho Power issued $250 million in principal amount of 3.65% first mortgage bonds, secured medium-term notes, Series J, maturing on March 1, 2045. On April 23, 2015, Idaho Power redeemed, prior to maturity, $120 million in principal amount of 6.025% first mortgage bonds, medium-term notes, Series H due July 2018. In accordance with the redemption provisions of the notes, the redemption included Idaho Power's payment of a make-whole premium to the holders of the redeemed notes in the aggregate amount of approximately $17.9 million. Idaho Power used a portion of the net proceeds from the March 2015 sale of first mortgage bonds, medium-term notes to effect the redemption.

In April 2013, Idaho Power received orders from the IPUC, OPUC, and Wyoming Public Service Commission (WPSC) authorizing Idaho Power to issue and sell from time to time up to $500 million in aggregate principal amount of debt securities and first mortgage bonds, subject to conditions specified in the orders. Authority from the IPUC was through April 9, 2015. On April 1, 2015, the IPUC approved a two-year extension through April 9, 2017, continuing Idaho Power's authorization to issue and sell from time to time debt securities and first mortgage bonds. 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 seven percent.

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, 2015, $250 million in principal amount of Series J Notes remained available for issuance under the Indenture.

In March 2016, Idaho Power issued $120 million in principal amount of 4.05% first mortgage bonds, secured medium-term notes, Series J, maturing on March 1, 2046. On March 10, 2016, Idaho Power issued a notice of redemption to redeem, prior to maturity, its $100 million in principal amount of 6.15% first mortgage bonds, medium-term notes, Series H due April 2019, with the redemption effective April 11, 2016. In accordance with the redemption provisions of the notes, the redemption included Idaho Power's payment of a make-whole premium to the holders of the redeemed notes in the aggregate amount of approximately $14 million. Idaho Power used a portion of the net proceeds from the March 2016 sale of first mortgage bonds, medium-term notes to effect the redemption.

Mortgage: As of December 31, 2015, Idaho Power could issue under its Indenture approximately $1.5 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 chooses 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

On November 6, 2015, Idaho Power entered into Credit Agreements replacing the existing Second Amended and Restated Credit Agreements, dated October 26, 2011, to provide credit facilities 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, and letters of credit in an aggregate principal amount at any time outstanding not to exceed $100 million. Idaho Power has the right to request an increase in the aggregate principal amount of the facilities to $450 million, subject to certain conditions.

The Idaho Power credit facility has similar terms and conditions. The interest rates for any borrowings under the facilities are based on either (1) a floating rate that is equal to the highest of the prime rate, federal funds rate plus 0.5 percent, or LIBOR rate plus 1.0 percent, or (2) the LIBOR rate, plus, in each case, an applicable margin, provided that the federal funds rate and LIBOR rate will not be less than 0.0 percent. The margin is based on Idaho Power's, as applicable; senior unsecured long-term indebtedness credit rating by Moody's Investors Service, Inc., Standard and Poor's Ratings Services, and Fitch Rating Services, Inc., as set forth on a schedule to the credit agreements. Under their respective credit facilities, the companies pay a facility fee on the commitment based on the respective company's credit rating for senior unsecured long-term debt securities. The credit facilities mature on November 6, 2020, though Idaho Power may request up to two one-year extensions of the credit agreements, subject to certain conditions.

At December 31, 2015 and December 31, 2014 no loans or commercial paper were outstanding under Idaho Power's facility. At December 31, 2015, Idaho Power had regulatory authority to incur up to $450 million in principal amount of short-term indebtedness at any one time outstanding.

6. COMMON STOCK

No contributions were made to Idaho Power in 2015 or 2014, 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 their respective credit facilities 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, 2015, the leverage ratio for Idaho Power was 48 percent. Based on these restrictions, Idaho Power's dividends were limited to $980 million, at December 31, 2015. 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, 2015, 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, 2015, Idaho Power's common equity capital was 52 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, 2015, the maximum number of shares available under the LTICP and RSP were 1,043,542 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 and the year issued, the final number of shares awarded can range from zero to 150 percent of the target award for awards granted prior to 2015 and from zero to 200 percent of the target award for awards granted in 2015. 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 portion of IDACORP common stock:

	Number of Shares	Weighted-Average Grant Date Fair Value
Nonvested shares at January 1, 2015	250,396	$ 43.91
Shares granted	115,863	54.05
Shares forfeited	(10,413)	55.63
Shares vested	(127,056)	36.84
Nonvested shares at December 31, 2015	228,790	$ 52.44

The total fair value of shares vested during the years ended December 31, 2015 and 2014 was $8.3 million and $6.6 million, respectively. At December 31, 2015, Idaho Power had $4.7 million of total unrecognized compensation cost related to nonvested share-based compensation that was expected to vest. These costs are expected to be recognized over a weighted-average period of 1.68 years. IDACORP uses original issue and/or treasury shares for these awards.

In 2015, a total of 15,324 of IDACORP common stock shares were awarded to directors of IDACORP and Idaho Power at a grant date fair value of $62.62 per share. Directors elected to defer receipt of 3,831 of these shares, which are being held as deferred stock units with dividend equivalents reinvested in additional stock units.

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):

	2015	2014
Compensation cost	$ 5,221	$ 5,458
Income tax benefit	2,042	2,134

No equity compensation costs have been capitalized.

8. COMMITMENTS

Purchase Obligations

At December 31, 2015, Idaho Power had the following long-term commitments relating to purchases of energy, capacity, transmission rights, and fuel (in thousands of dollars):

	2016	2017	2018	2019	2020	Thereafter
Cogeneration and power production	$ 199,156	$ 233,197	$ 241,356	$ 234,772	$ 234,316	$ 3,592,891
Fuel	60,122	43,276	16,206	9,169	8,833	114,417

As of December 31, 2015, Idaho Power had 784 MW nameplate capacity of PURPA-related projects on-line, with an additional 448 MW nameplate capacity of projects projected to be on-line by June 1, 2017. Of the 448 MW nameplate capacity of projected PURPA-related projects at the end of 2015, as of February 5, 2016, three contracts with solar projects with a combined nameplate capacity of 25 MW had terminated. Termination of the agreements reduced Idaho Power's contractual payment obligations by approximately $74 million over the 20-year lives of the terminated contracts. 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 $131 million in 2015 and $145 million in 2014.

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

	2016	2017	2018	2019	2020	Thereafter
Operating leases	$ 233	$ 971	$ 985	$ 1,062	$ 897	$ 12,625
Equipment, maintenance, and service agreements	48,707	11,703	14,869	9,214	12,095	83,721
FERC and other industry-related fees	12,894	12,746	12,746	8,632	5,942	29,708

Idaho Power's expense for operating leases was approximately $4.4 million in 2015 and $5.9 million in 2014.

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 $73 million at December 31, 2015, 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, 2015, the value of the reclamation trust fund was $70 million. During 2015, the reclamation trust fund distributed approximately $6 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 their historical experience and the evaluation of the specific indemnities. As of December 31, 2015, management believes the likelihood is remote that Idaho Power would be required to perform under such indemnification provisions or otherwise incur any significant losses with respect to such indemnification obligations. Idaho Power has not recorded any liability on its 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 the western wholesale markets during 2000 and 2001 caused numerous purchasers of electricity in those markets to initiate proceedings to consider requiring refunds and other forms of disgorgement from energy sellers. Some of these proceedings remain pending before the FERC or are on appeal to the United States Court of Appeals for the Ninth Circuit, and thus there remains some uncertainty about the ultimate outcome of the proceedings. Idaho Power and IESCo (as successor to IDACORP Energy L.P.) believe that the current state of the FERC's orders, if maintained, and the settlement releases they have obtained, will restrict potential claims that might result from the pending proceedings. As a result, Idaho Power predicts that these matters will not have a material adverse effect on the results of operations or financial condition. However, if unanticipated orders are issued by the FERC or by the Ninth Circuit Court of Appeals or other courts, exposure to indirect claims in the proceedings could exist. These indirect claims would consist of 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. Given the speculative nature of ripple claims and in light of Idaho Power's and IESCo participating in the market as both a buyer and seller of energy, Idaho Power and IESCo are unable to estimate the possible loss or range of loss that could result from the proceedings and 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.

Hoku Corporation Bankruptcy Claims

On June 26, 2015, the trustee in the Hoku Corporation chapter 7 bankruptcy case (*In Re: Hoku Corporation*, United States Bankruptcy Court, District of Idaho, Case No. 13-40838 JDP) filed a complaint against Idaho Power, alleging that specified payments made by Hoku Corporation to Idaho Power in the six years prior to Hoku Corporation's bankruptcy filing in July 2013 should be recoverable by the trustee as constructive fraudulent transfers. Hoku Corporation was the parent entity of Hoku Materials, Inc., with which Idaho Power had an electric service agreement approved by the IPUC in March 2009. Under the electric service agreement, Idaho Power agreed to provide electric service to a polysilicon production facility under construction by Hoku Materials in the state of Idaho. Idaho Power also had agreements with Hoku Materials pertaining to the design and construction of apparatus for the provision of electric service to the polysilicon plant. The trustee's complaint against Idaho Power includes alternative causes of action for constructive fraudulent transfer under the federal bankruptcy code, Idaho law, and federal law, with requests for recovery from Idaho Power in amounts up to approximately $36 million. The complaint alleges that the payments made by Hoku Corporation to Idaho Power are subject to recovery by the trustee on the basis that Hoku Corporation was insolvent at the time of the payments and did not have any legal or equitable title in the polysilicon plant or liability for Hoku Materials' debts, and thus did not receive reasonably equivalent value for the payments it made for or on behalf of Hoku Materials.

As of the date of this report, the proceedings are in preliminary stages and it is not possible to determine Idaho Power's potential liability, if any, or to reasonably estimate a possible loss or range of possible loss, if any, within the trustee's alternative prayers for relief. Idaho Power intends to vigorously defend against the claims.

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, record 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 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. However, Idaho Power does believe that future capital investment for infrastructure and modifications to its electric generating facilities could be significant to comply with these regulations.

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 were 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 2015, and 2014 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		SMSP	
	2015	2014	2015	2014
Change in projected benefit obligation:				
Benefit obligation at January 1	$ 844,812	$ 695,093	$ 94,410	$ 77,773
Service cost	33,164	25,292	1,689	1,645
Interest cost	35,171	35,415	3,868	3,856
Actuarial (gain) loss	(47,952)	114,496	(352)	15,324
Benefits paid	(29,672)	(25,484)	(4,226)	(4,188)
Projected benefit obligation at December 31	835,523	844,812	95,389	94,410
Change in plan assets:				
Fair value at January 1	559,719	545,092	—	—
Actual return on plan assets	(9,431)	10,111	—	—
Employer contributions	39,000	30,000	—	—
Benefits paid	(29,672)	(25,484)	—	—
Fair value at December 31	559,616	559,719	—	—
Funded status at end of year	$ (275,907)	$ (285,093)	$ (95,389)	$ (94,410)
Amounts recognized in the statement of financial position consist of:				
Other current liabilities	$ —	$ —	$ (4,423)	$ (4,193)
Noncurrent liabilities	(275,907)	(285,093)	(90,966)	(90,217)
Net amount recognized	(275,907)	(285,093)	(95,389)	(94,410)
Amounts recognized in accumulated other comprehensive income consist of:				
Net loss	253,212	263,350	34,260	38,808
Prior service cost	74	295	673	857
Subtotal	253,286	263,645	34,933	39,665
Less amount recorded as regulatory asset	(253,286)	(263,645)	—	—
Net amount recognized in accumulated other comprehensive income	$ —	$ —	$ 34,933	$ 39,665
Accumulated benefit obligation	$ 714,994	$ 719,617	$ 86,838	$ 84,684

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 recorded value of these investments was approximately $69.3 million and $65.0 million at December 31, 2015 and 2014, 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		SMSP	
	2015	2014	2015	2014
Service cost	$ 33,164	$ 25,292	$ 1,689	$ 1,645
Interest cost	35,171	35,415	3,868	3,856
Expected return on assets	(42,310)	(42,289)	—	—
Amortization of net loss	13,927	3,911	4,195	2,618
Amortization of prior service cost	221	347	185	220
Net periodic pension cost	40,173	22,676	9,937	8,339
Adjustments due to the effects of regulation[1]	(21,173)	12,124	—	—
Net periodic benefit cost recognized for financial reporting	$ 19,000	$ 34,800	$ 9,937	$ 8,339

(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		SMSP	
	2015	2014	2015	2014
Actuarial (loss) gain during the year	$ (3,790)	$ (146,674)	$ 353	$ (15,324)
Reclassification adjustments for:				
Amortization of net loss	13,927	3,911	4,195	2,618
Amortization of prior service cost	221	347	185	220
Adjustment for deferred tax effects	(4,050)	55,678	(1,851)	4,881
Adjustment due to the effects of regulation	(6,308)	86,738	—	—
Other comprehensive income recognized related to pension benefit plans	$ —	$ —	$ 2,882	$ (7,605)

In 2016, Idaho Power expects to recognize as components of net periodic benefit cost $17.3 million from amortizing amounts recorded in accumulated other comprehensive income (or as a regulatory asset for the pension plan) as of December 31, 2015, relating to the pension plan and SMSP. This amount consists of $13.5 million of amortization of net loss and $0.1 million of amortization of prior service cost for the pension plan, and $3.5 million of amortization of net loss and $0.2 million of amortization of prior service cost for the SMSP.

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

	2016	2017	2018	2019	2020	2021-2025
Pension Plan	$ 30,086	$ 32,529	$ 35,156	$ 37,795	$ 40,527	$ 241,079
SMSP	4,516	4,582	4,371	4,547	4,964	25,659

As of December 31, 2015, Idaho Power's minimum required contributions to the pension plan are estimated to be zero in 2016, though Idaho Power plans to contribute at least $20 million to the pension plan during 2016 in order to help balance the regulatory collection of these expenditures with the amount and timing of contributions and to mitigate the cost of being in an underfunded position.

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):

	2015	2014
Change in accumulated benefit obligation:		
Benefit obligation at January 1	$ 65,999	$ 57,341
Service cost	1,235	1,011
Interest cost	2,678	2,841
Actuarial (gain) loss	(5,008)	7,026
Benefits paid(1)	(2,511)	(2,220)
Benefit obligation at December 31	62,393	65,999
Change in plan assets:		
Fair value of plan assets at January 1	38,375	37,111
Actual return on plan assets	85	3,888
Employer contributions(1)	(383)	(404)
Benefits paid(1)	(2,511)	(2,220)
Fair value of plan assets at December 31	35,566	38,375
Funded status at end of year (included in noncurrent liabilities)	$ (26,827)	$ (27,624)

(1) Contributions and benefits paid are each net of $3,518 thousand and $3,379 thousand of plan participant contributions, and $330 thousand and $344 thousand of Medicare Part D subsidy receipts for 2015 and 2014, respectively.

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

	2015	2014
Net (gain) loss	$ (1,654)	$ 759
Prior service cost	130	145
Subtotal	(1,524)	904
Less amount recognized in regulatory assets	1,524	(904)
Net amount recognized in accumulated other comprehensive income	$ —	$ —

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

	2015	2014
Service cost	$ 1,235	$ 1,011
Interest cost	2,678	2,841
Expected return on plan assets	(2,680)	(2,595)
Amortization of prior service cost	15	183
Net periodic postretirement benefit cost	$ 1,248	$ 1,440

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

	2015	2014
Actuarial gain (loss) during the year	$ 2,413	$ (5,733)
Reclassification adjustments for:		
Amortization of prior service cost	15	183
Adjustment for deferred tax effects	(949)	2,170
Adjustment due to the effects of regulation	(1,479)	3,380
Other comprehensive income related to postretirement benefit plans	$ —	$ —

In 2016, Idaho Power expects to recognize as components of net periodic benefit cost $26 thousand from amortizing amounts recorded in accumulated other comprehensive income as of December 31, 2015, relating to the postretirement benefit plan. The entire amount represents $26 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):

	2016	2017	2018	2019	2020	2021-2025
Expected benefit payments	$4,010	$4,050	$4,100	$4,150	$4,190	$21,030
Expected Medicare Part D subsidy receipts	380	430	470	510	560	3,480

Plan Assumptions

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

	Pension Plan		SMSP		Postretirement Benefits	
	2015	2014	2015	2014	2015	2014
Discount rate	4.6%	4.25%	4.6%	4.2%	4.6%	4.2%
Rate of compensation increase[1]	4.11%	4.3%	4.5%	4.5%	—	—
Medical trend rate	—	—	—	—	9.7%	6.4%
Dental trend rate	—	—	—	—	5%	5%
Measurement date	12/31/2015	12/31/2014	12/31/2015	12/31/2014	12/31/2015	12/31/2014

(1) The 2015 rate of compensation increase assumption for the pension plan includes an inflation component of 2.50% plus a 1.61% 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		SMSP		Postretirement Benefits	
	2015	2014	2015	2014	2015	2014
Discount rate	4.25%	5.2%	4.2%	5.1%	4.2%	5.15%
Expected long-term rate of return on assets	7.5%	7.75%	—	—	7.25%	7.25%
Rate of compensation increase	4.11%	4.3%	4.5%	4.5%	—	—
Medical trend rate	—	—	—	—	9.7%	6.4%
Dental trend rate	—	—	—	—	5%	5%

In October 2014, the Society of Actuaries released a new set of mortality tables referred to as RP-2014. Mortality tables are used by defined benefit plans to estimate the life expectancy of plan participants and the expected length of benefit payments in retirement. Idaho Power's measurement of its plan benefit obligations as of December 31, 2015 and 2014, and its net periodic benefit cost for 2015, reflect the adoption of the new tables, which was not material.

The assumed health care cost trend rate used to measure the expected cost of health benefits covered by the postretirement plan was 9.7 percent in 2015 and is assumed to decrease to 8.3 percent in 2016, 6.8 percent in 2017, and 5.4 percent in 2018 and to gradually decrease to 4.8 percent by 2099. The assumed dental cost trend rate used to measure the expected cost of dental benefits covered by the plan was 5.0 percent, or equal to the medical trend rate if lower, for all years. A one percentage point change in the assumed health care cost trend rate would have the following effects at December 31, 2015 (in thousands of dollars):

	One-Percentage-Point Increase	Decrease
Effect on total of cost components	$ 407	$ (297)
Effect on accumulated postretirement benefit obligation	3,719	(2,838)

Plan Assets

Pension Asset Allocation Policy: The target allocation and actual allocations at December 31, 2015 for the pension asset portfolio by asset class is set forth below:

Asset Class	Target Allocation	Actual Allocation December 31, 2015
Debt securities	24%	25%
Equity securities	54%	55%
Real estate	6%	7%
Other plan assets	16%	13%
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, 2015				
Pension plan assets:				
Cash and cash equivalents	$ 10,519	$ —	$ —	$ 10,519
Short-term bonds	11,023	—	—	11,023
Intermediate bonds	11,499	92,742	—	104,241
Long-term bonds	—	21,747	—	21,747
Equity Securities: Large-Cap	73,489	—	—	73,489
Equity Securities: Mid-Cap	64,397	—	—	64,397
Equity Securities: Small-Cap	47,777	—	—	47,777
Equity Securities: Micro-Cap	22,186	—	—	22,186
Equity Securities: International	7,698	59,787	—	67,485
Equity Securities: Emerging Markets	9,679	23,167	—	32,846
Real estate	—	—	39,035	39,035
Private market investments	—	—	37,316	37,316
Commodities funds	—	27,555	—	27,555
Total pension assets	$ 258,267	$ 224,998	$ 76,351	$ 559,616
Postretirement plan assets(1)	$ 16	$ 35,550	$ —	$ 35,566
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

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

For the year ended December 31, 2015, there were no significant transfers into or out of Levels 1, 2, or 3. For the year ended December 31, 2014, there were $23.1 million of mid-cap equity security investments that were transferred from Level 2 to Level 1.

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, 2014	$ 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
Realized gains	1,897	923	2,820
Unrealized (losses) gains	(3,152)	3,193	41
Purchases	2,255	923	3,178
Sales	(802)	—	(802)
Ending balance - December 31, 2015	$ 37,316	$ 39,035	$ 76,351

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 from 2014 to 2015.

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 both December 31, 2015 and 2014 were $2.0 million.

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 2015 and 2014 (in thousands of dollars):

	2015		2014	
	Balance	**Avg Rate**	**Balance**	**Avg Rate**
Production	$ 2,422,175	2.46%	$ 2,316,941	2.48%
Transmission	1,077,065	2.01%	1,016,207	2.03%
Distribution	1,578,445	2.72%	1,516,933	2.72%
General and Other	407,779	5.62%	398,131	5.49%
Total in service	5,485,464	2.68%	5,248,212	2.68%
Accumulated provision for depreciation	(2,097,432)		(2,021,074)	
In service - net	$ 3,388,032		$ 3,227,138	

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, 2015 (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	$ 641,382	$ 46,094	$ 296,671	33	771
Boardman	Boardman, OR	81,252	113	63,715	10	64
Valmy Units 1 and 2	Winnemucca, NV	402,276	1,135	184,604	50	284

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

IERCo, Idaho Power's wholly-owned subsidiary, is a joint venturer in BCC. Idaho Power's coal purchases from the joint venture were $93 million in 2015 and $79 million in 2014.

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 $8 million in 2015 and $9 million in 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 2015, changes in estimates at its distribution facilities and at the coal-fired generation facilities resulted in a net increase of $5.0 million in the recorded AROs. The increase in the AROs in 2015 is primarily related to the impact of new coal combustion residual regulations on the Bridger 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):

	2015	2014
Balance at beginning of year	$ 21,930	$ 25,765
Accretion expense	993	1,061
Revisions in estimated cash flows	5,043	(4,140)
Liability settled	(1,813)	(756)
Balance at end of year	$ 26,153	$ 21,930

13. INVESTMENTS

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

	2015	2014
Idaho Power investments:		
IERCO	$ 84,137	$ 83,477
Exchange traded short-term bond funds and cash equivalents	24,459	44,942
Executive deferred compensation plan investments	102	141
Other investments	—	1
Total Idaho Power investments	108,698	128,561

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, 2015 and December 31, 2014. The following table summarizes sales of available-for-sale securities (in thousands of dollars):

	2015	2014
Proceeds from sales	$ 34,243	$ —
Gross realized gains from sales	—	—
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, 2015 and December 31, 2014, 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, 2015 and 2014 (in thousands of dollars):

	Location of Realized Gain/(Loss) on Derivatives Recognized in Income	Gain/(Loss) on Derivatives Recognized in Income[(1)]	
		2015	2014
Financial swaps	Off-system sales	$ 2,882	$ (4,119)
Financial swaps	Purchased power	748	(1,416)
Financial swaps	Fuel expense	(6,045)	3,862
Financial swaps	Other operations and maintenance	(50)	(158)
Forward contracts	Off-system sales	—	277
Forward contracts	Purchased power	(6)	(279)
Forward contracts	Fuel expense	54	94

(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, 2015 and 2014 (in thousands of dollars):

		Asset Derivatives			Liability Derivatives		
	Balance Sheet Location	Gross Fair Value	Amounts Offset	Net Assets	Gross Fair Value	Amounts Offset	Net Liabilities
December 31, 2015							
Current:							
Financial swaps	Other current assets	$ 999	$ (785)	$ 214	$ 785	$ (785)	$ —
Financial swaps	Other current liabilities	177	(177)	—	5,146	(177)	4,969
Forward contracts	Other current assets	64	—	64	—	—	—
Forward contracts	Other current liabilities	—	—	—	3	—	3
Long-term:							
Financial swaps	Other assets	148	(22)	126	22	(22)	—
Total		$ 1,388	$ (984)	$ 404	$ 5,956	$ (984)	$ 4,972
December 31, 2014							
Current:							
Financial swaps	Other current assets	$ 2,509	$ (2,002)	$ 507	$ 756	$ (756)	$ —
Financial swaps	Other current liabilities	379	(379)	—	4,335	(379)	3,956
Forward contracts	Other current assets	64	—	64	—	—	—
Forward contracts	Other current liabilities	—	—	—	5	—	5
Long-term:							
Forward contracts	Other assets	63	—	63	—	—	—
Total		$ 3,015	$ (2,381)	$ 634	$ 5,096	$ (1,135)	$ 3,961

(1) Current asset and current liability derivative amounts offset include $0.9 million of collateral receivable and $1.2 million of collateral payable and for the periods ending December 31, 2015 and 2014, respectively.

The table below presents the volumes of derivative commodity forward contracts and swaps outstanding at December 31, 2015 and 2014 (in thousands of units):

		December 31,	
Commodity	**Units**	**2015**	**2014**
Electricity purchases	MWh	357	115
Electricity sales	MWh	120	238
Natural gas purchases	MMBtu	11,597	6,913
Natural gas sales	MMBtu	78	409
Diesel purchases	Gallons	1,068	243

Credit Risk

At December 31, 2015, 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, 2015, was $5.7 million. Idaho Power posted $0.9 million cash collateral related to this amount. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2015, Idaho Power would have been required to post an additional $9.0 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, 2015 and 2014.

The following table presents information about Idaho Power's assets and liabilities measured at fair value on a recurring basis as of December 31, 2015 and 2014 (in thousands of dollars):

	December 31, 2015				December 31, 2014			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets:								
-Money market funds	10,000	—	—	10,000	100	—	—	100
Derivatives	340	64	—	404	506	128	—	634
Trading securities: Equity securities	102	—	—	102	141	—	—	141
Available-for-sale securities: ETFs	24,459	—	—	24,459	44,942	—	—	44,942
Liabilities:								
Derivatives	$ 286	$ 4,686	$ —	$ 4,972	$ 17	$ 3,944	$ —	$ 3,961

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 exchange-traded short-term bond and money market funds related to the SMSP and are held in a Rabbi Trust.

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, 2015 and 2014, using available market information and appropriate valuation methodologies (in thousands of dollars):

	December 31, 2015		December 31, 2014	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
Liabilities:				
Long-term debt(1)	$ 1,726,474	$ 1,813,243	$ 1,615,502	$ 1,788,197

(1 long-term debt is categorized as Level 3 and Level 2, respectively, of 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

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, 2015, and 2014, (in thousands of dollars). Items in parentheses indicate increases to net income.

	Amount Reclassified from AOCI Year Ended December 31,	
	2015	**2014**
Unrealized gains on available-for-sale securities		
Realized gain on sale of securities, before tax(1)	$	$
Tax benefit(2)	—	—
Net of tax	—	—
Amortization of defined benefit pension items(3)		
Prior service cost	185	220
Net loss	4,195	2,618
Total before tax	4,380	2,838
Tax benefit(2)	(1,712)	(1,110)
Net of tax	2,668	1,728
Total reclassification for the period	$ 2,668	$ 1,728

(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 statements 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 $0.9 million in 2015 and $1.4 million in 2014.

Ida-West: Idaho Power purchases all of the power generated by four of Ida-West's hydroelectric projects located in Idaho. Idaho Power paid Ida-West $8 million in 2015 and $9 million in 2014.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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)	5,485,463,707	5,485,463,707
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	5,485,463,707	5,485,463,707
9	Leased to Others		
10	Held for Future Use	7,090,431	7,090,431
11	Construction Work in Progress	396,931,372	396,931,372
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	5,889,485,510	5,889,485,510
14	Accum Prov for Depr, Amort, & Depl	2,097,432,010	2,097,432,010
15	Net Utility Plant (13 less 14)	3,792,053,500	3,792,053,500
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	2,071,784,276	2,071,784,276
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	25,647,734	25,647,734
22	Total In Service (18 thru 21)	2,097,432,010	2,097,432,010
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)	2,097,432,010	2,097,432,010

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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	29,296,781	462,901
4	(303) Miscellaneous Intangible Plant	29,627,507	3,479,891
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	58,929,991	3,942,792
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,712,208	18,263
9	(311) Structures and Improvements	150,084,364	3,911,857
10	(312) Boiler Plant Equipment	595,163,147	100,272,650
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	159,336,727	13,999,188
13	(315) Accessory Electric Equipment	70,043,047	816,126
14	(316) Misc. Power Plant Equipment	15,934,815	2,104,268
15	(317) Asset Retirement Costs for Steam Production	6,372,118	7,557,943
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	998,646,426	128,680,295
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	31,188,341	35,573
28	(331) Structures and Improvements	175,002,423	1,215,068
29	(332) Reservoirs, Dams, and Waterways	262,578,901	7,483,596
30	(333) Water Wheels, Turbines, and Generators	207,190,561	5,110,769
31	(334) Accessory Electric Equipment	56,827,891	1,778,270
32	(335) Misc. Power PLant Equipment	21,769,922	1,140,922
33	(336) Roads, Railroads, and Bridges	9,584,640	1,295,862
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	764,142,679	18,060,060
36	D. Other Production Plant		
37	(340) Land and Land Rights	2,690,006	
38	(341) Structures and Improvements	140,902,354	1,808,711
39	(342) Fuel Holders, Products, and Accessories	10,452,547	
40	(343) Prime Movers	238,896,447	858,744
41	(344) Generators	66,355,256	176,620
42	(345) Accessory Electric Equipment	88,607,565	2,591,423
43	(346) Misc. Power Plant Equipment	6,247,393	-236,918
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	554,151,568	5,198,580
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	2,316,940,673	151,938,935

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

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

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

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

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
			5,703		2
			29,759,682		3
4,613,599			28,493,799		4
4,613,599			58,259,184		5
					6
					7
			1,730,471		8
587,492			153,408,729		9
12,546,647			682,889,150		10
					11
10,791,836			162,544,079		12
157,384			70,701,789		13
535,197			17,503,886		14
			13,930,061		15
24,618,556			1,102,708,165		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			31,223,914		27
221,120			175,996,371		28
102,655			269,959,842		29
621,974			211,679,356		30
131,843			58,474,318		31
114,581			22,796,263		32
			10,880,502		33
					34
1,192,173			781,010,566		35
					36
			2,690,006		37
			142,711,065		38
			10,452,547		39
20,794,299			218,960,892		40
			66,531,876		41
100,000			91,098,988		42
			6,010,475		43
					44
20,894,299			538,455,849		45
46,705,028			2,422,174,580		46

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	36,146,124	232,955
49	(352) Structures and Improvements	72,737,991	5,128,194
50	(353) Station Equipment	399,787,968	11,017,730
51	(354) Towers and Fixtures	168,186,852	16,612,039
52	(355) Poles and Fixtures	142,597,655	16,669,245
53	(356) Overhead Conductors and Devices	196,360,600	16,587,047
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)	1,016,207,456	66,247,210
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	5,175,131	125,393
61	(361) Structures and Improvements	33,716,699	493,837
62	(362) Station Equipment	202,030,200	16,141,880
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	241,088,379	8,202,243
65	(365) Overhead Conductors and Devices	128,008,024	3,488,928
66	(366) Underground Conduit	47,294,326	1,240,181
67	(367) Underground Conductors and Devices	218,656,607	13,091,098
68	(368) Line Transformers	494,614,876	28,686,286
69	(369) Services	57,867,385	1,245,760
70	(370) Meters	80,528,574	4,777,999
71	(371) Installations on Customer Premises	2,914,525	111,792
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	4,504,500	89,586
74	(374) Asset Retirement Costs for Distribution Plant	533,712	-369,521
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,516,932,938	77,325,462
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	16,578,582	
87	(390) Structures and Improvements	107,038,338	6,306,655
88	(391) Office Furniture and Equipment	45,902,762	4,656,977
89	(392) Transportation Equipment	74,214,375	8,247,219
90	(393) Stores Equipment	1,936,397	359,137
91	(394) Tools, Shop and Garage Equipment	7,574,780	602,385
92	(395) Laboratory Equipment	12,652,489	396,754
93	(396) Power Operated Equipment	13,938,120	1,923,220
94	(397) Communication Equipment	53,788,304	3,488,278
95	(398) Miscellaneous Equipment	5,577,125	511,022
96	SUBTOTAL (Enter Total of lines 86 thru 95)	339,201,272	26,491,647
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)	339,201,272	26,491,647
100	TOTAL (Accounts 101 and 106)	5,248,212,330	325,946,046
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)	5,248,212,330	325,946,046

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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
			36,379,079		48
85,939			77,780,246		49
3,203,069			407,602,629		50
170,836			184,628,055		51
886,706			158,380,194		52
1,042,990			211,904,657		53
					54
					55
			390,266		56
					57
5,389,540			1,077,065,126		58
					59
			5,300,524		60
35,183			34,175,353		61
1,318,351			216,853,729		62
					63
2,304,956			246,985,666		64
2,165,484			129,331,468		65
211,898			48,322,609		66
1,604,537			230,143,168		67
7,648,883			515,652,279		68
342,381			58,770,764		69
59,115			85,247,458		70
71,859			2,954,458		71
					72
50,837			4,543,249		73
			164,191		74
15,813,484			1,578,444,916		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			16,578,582		86
2,420,337			110,924,656		87
3,867,656			46,692,083		88
6,582,731			75,878,863		89
40,131			2,255,403		90
155,609			8,021,556		91
345,424			12,703,819		92
779,305			15,082,035		93
1,861,382			55,415,200		94
120,443			5,967,704		95
16,173,018			349,519,901		96
					97
					98
16,173,018			349,519,901		99
88,694,669			5,485,463,707		100
					101
					102
					103
88,694,669			5,485,463,707		104

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Boise Operations Center	12/31/82		655,550
3	Production			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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

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

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	ROLLUP RELIC COST BROWNLEE	86,963,920
2	ROLLUP RELIC COST HELLS CANYON	59,261,154
3	BRIDGER 2011C039 JB4 SCR SYS D	37,547,331
4	GATEWAY WEST 500KV LINE	29,199,462
5	ROLLUP RELIC COST OXBOW	27,524,739
6	HELLS CANYON RELICENSING OUTSI	22,519,224
7	BOARDMAN - HEMINGWAY 500 KV LI	11,567,064
8	B2H PERMITTING 11/1/2011 & FOR	9,853,267
9	BROWNLEE TURBINE REFURBISHMENT	9,811,096
10	LOWER SALMON RUNNER REPLACEMEN	6,896,703
11	BROWNLEE UNIT 1 TURBINE REFURB	6,339,392
12	HCC WATERSHED ENHANCEMENT PROG	3,816,660
13	LEGAL DEPT. LABOR FOR RELICENS	3,285,241
14	BRIDGER UNDISTRIBUTED WORK ORD	3,283,000
15	REL-HCC OREGON REAUTHORIZATION	2,654,393
16	B2H TLINE CONSTRUCTION COSTS	2,479,755
17	MPSN T501 - REPLACE FAILED 500	2,362,687
18	REWIND GENERATOR STATOR #4	2,136,864
19	WQ HCC401 CERTIFICATION OPS AN	1,982,499
20	WDRI-KCHM NEW 138KV	1,643,935
21	WQ HCC401 APPLICATION, REVISIO	1,566,482
22	FALL CHINOOK PROGRAM - REDD SU	1,410,685
23	HBND-041:ALT LINE ROUTE TO GAR	1,405,061
24	RELICENSING: BAKER COUNTY SETT	1,380,185
25	T216 7.1 MILES OF 69KV LINE FR	1,353,368
26	BRIDGER 2015C070 U4 REPLACE FI	1,315,646
27	REC - BAKER COUNTY SETTLEMENT	1,260,702
28	HEMINGWAY 500 KV IN AND OUT RE	1,233,651
29	T4331001-UPGRADE T433 TO 230KV	1,203,508
30	314 DESIGN TEAMS - CAPITAL - C	1,112,931
31	BULL TROUT PROGRAM - ADMINISTR	1,109,406
32	METEOROLOGY MODEL FOR OPERATIO	1,079,859
33	BROWNLEE UNIT 3 TURBINE REFURB	1,004,404
34	OTHER MINOR PROJECTS UNDER $1,000,000	49,367,098
35		
36		
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41		
42		
43	TOTAL	396,931,372

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/Q4

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

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

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)
	Section A. Balances and Changes During Year				
1	Balance Beginning of Year	1,997,908,418	1,997,908,418		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	130,382,128	130,382,128		
4	(403.1) Depreciation Expense for Asset Retirement Costs	549,017	549,017		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	3,896,082	3,896,082		
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)	134,929,440	134,929,440		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	84,081,070	84,081,070		
13	Cost of Removal	13,728,966	13,728,966		
14	Salvage (Credit)	26,189,699	26,189,699		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	71,620,337	71,620,337		
16	Other Debit or Cr. Items (Describe, details in footnote):	10,566,755	10,566,755		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	2,071,784,276	2,071,784,276		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	540,252,070	540,252,070		
21	Nuclear Production				
22	Hydraulic Production-Conventional	402,629,313	402,629,313		
23	Hydraulic Production-Pumped Storage				
24	Other Production	90,194,940	90,194,940		
25	Transmission	337,675,154	337,675,154		
26	Distribution	590,665,462	590,665,462		
27	Regional Transmission and Market Operation				
28	General	110,367,337	110,367,337		
29	TOTAL (Enter Total of lines 20 thru 28)	2,071,784,276	2,071,784,276		

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

CIAC, Reserve Adjustments and Asset Retirement Obligation activity.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

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

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	Idaho Energy Resources Company			
2	Common Stock	02/01/74		500
3	Capital contributions			2,462,594
4	Equity in earnings			81,014,366
5				
6	Subtotal Idaho Energy Resources Company			83,477,460
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41				
42	Total Cost of Account 123.1 $ 2,463,094		TOTAL	83,477,460

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
6,659,942	6,000,000	81,674,307		4
				5
6,659,942	6,000,000	84,137,401		6
				7
				8
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6,659,942	6,000,000	84,137,401		42

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)	55,170,482	61,818,257	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)	17,010,420	17,384,869	
8	Transmission Plant (Estimated)	11,212,105	11,191,094	
9	Distribution Plant (Estimated)	20,564,459	21,957,543	
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	1,518,495	1,911,722	
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	50,305,479	52,445,228	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)	5,098,760	4,478,320	Electric
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	110,575,320	118,741,805	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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	BPAP NETWORK SIS 78318516	12,245	186623	(7,270)	186623
3	BPAP TRANS SIS 80289606		186623	8,169	186623
4	PAC PTP SIS 80381517	2,367	186623	7,633	186623
5					
6					
7					
8					
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12					
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	LAGOON SOLAR #490	1,624	186623.00000	(1,624)	186623.00000
23	LITTLE VALLEY SOLAR 491	3,571	186623.00000	(11,430)	186623.00000
24	ACADIA SOLAR #474	5,095	186623.00000	(5,095)	186623.00000
25	ADA PV2-A #482	15,932	186623.00000	(15,932)	186623.00000
26	ADA PV2-B #483	14,796	186623.00000	(14,796)	186623.00000
27	AMERICAN FALLS SOLAR # 431	35,941	186623.00000	(26,415)	186623.00000
28	AMERICAN FALLS SOLAR II # 433	20,518	186623.00000	(13,735)	186623.00000
29	BAKER SOLAR 1 #507	1,046	186623.00000	(1,000)	186623.00000
30	BAKER SOLAR 2 #508	1,047	186623.00000	(1,000)	186623.00000
31	BENSON CREEK WINDFARM GI 401		186623.00000	85,666	186623.00000
32	BIG DOG SOLAR #470	5,024	186623.00000	(5,024)	186623.00000
33	BOISE CITY SOLAR #432	34,164	186623.00000	(65,289)	186623.00000
34	BRUSH SOLAR #500	914	186623.00000	(914)	186623.00000
35	BUTLER SOLAR #471	3,872	186623.00000	(3,872)	186623.00000
36	CHERRY LANE SOLAR #462 10MW	709	186623.00000	(709)	186623.00000
37	CLARK 2 SOLAR-20MW #438	9,001	186623.00000	(8,086)	186623.00000
38	CLARK 4 SOLAR-20MW #440	8,908	186623.00000	(7,993)	186623.00000
39	CLARK SOLAR 1 #437 7MW	13,763	186623.00000	(4,620)	186623.00000
40	CLARK SOLAR 3 #439 30MW	10,267	186623.00000	(437)	186623.00000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/Q4

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	COOPER SOLAR #478	2,184	186623.00000	(2,184)	186623.00000
23	DAVIS SOLAR # 506	1,102	186623.00000	(1,000)	186623.00000
24	DAVIS SOLAR #498	207	186623.00000	(207)	186623.00000
25	DURKEE SOLAR #496	1,630	186623.00000	(1,630)	186623.00000
26	EVERGREEN SOLAR #475	8,020	186623.00000	(43,964)	186623.00000
27	FAIRWAY SOLAR #493	5,601	186623.00000	(12,933)	186623.00000
28	FALLS CITY SOLAR #461 10MW	1,568	186623.00000	(1,568)	186623.00000
29	FOURTH AVE. SOLAR #481	2,849	186623.00000	(2,849)	186623.00000
30	GRANDVIEW PV SOLAR FIVE GI 411		186623.00000	1,578	186623.00000
31	GROVE SOLAR CENTER - GI 414	1,753	186623.00000	20,351	186623.00000
32	HUNTINGTON SOLAR 1 #505	954	186623.00000	(1,000)	186623.00000
33	HYLINE SOLAR CENTER - GI 419	4,177	186623.00000	10,942	186623.00000
34	IPCL TRANS SIS 80914710	1,025	186623.00000	(1,025)	186623.00000
35	JACKPOT SOLAR NORTH #502	9,446	186623.00000	(11,000)	186623.00000
36	JACKPOT SOLAR SOUTH #503	9,631	186623.00000	(11,000)	186623.00000
37	JAMIESON SOLAR #472	5,830	186623.00000	(5,830)	186623.00000
38	JOHN DAY SOLAR #480	4,822	186623.00000	(44,324)	186623.00000
39	KINGMAN SOLAR 489	2,794	186623.00000	(2,794)	186623.00000
40	LUTHER SOLAR #492	324	186623.00000	(324)	186623.00000

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/Q4

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	MAHLHUER RIVER SOLAR #477	5,776	186623.00000	(32,689)	186623.00000
23	MERIDIAN/NORTH RD PV1-A	1,958	186623.00000	(11,518)	186623.00000
24	MERIDIAN/NORTH RD PV1-B #485	1,581	186623.00000	(1,581)	186623.00000
25	MOORES HOLLOW #476	6,610	186623.00000	(42,981)	186623.00000
26	MORTH GOODING MAIN HYDRO #494	3,494	186623.00000	(25,075)	186623.00000
27	MOUTAIN HOME SOLAR-20MW #435	29,563	186623.00000	(47,195)	186623.00000
28	MT. HOME SOLAR #444	1,211	186623.00000	(211)	186623.00000
29	MURPHY FLAT POWER NORTH #426	42,708	186623.00000	(37,772)	186623.00000
30	MURPHY FLAT POWER SOUTH #427		186623.00000	(2,540)	186623.00000
31	OLD FERRY ROAD SOLAR #473	8,743	186623.00000	(44,281)	186623.00000
32	ONTARIO SOLAR #504	1,013	186623.00000	(1,000)	186623.00000
33	OPEN RANGE SOLAR CENTER - GI 413	1,681	186623.00000	8,737	186623.00000
34	ORCHARD RANCH 2 #488		186623.00000	(10,000)	186623.00000
35	ORCHARD RANCH SOLAR-20MW #441	37,093	186623.00000	(52,867)	186623.00000
36	OWYHEE SOLAR #479	5,750	186623.00000	(5,750)	186623.00000
37	POCATELLO SOLAR-20MW #436	15,230	186623.00000	(33,041)	186623.00000
38	RAILROAD SOLAR CENTER - GI 423	9,127	186623.00000	16,063	186623.00000
39	RAILROAD SOLAR CENTER - GI 424	5,281	186623.00000	13,759	186623.00000
40	SALMON RIVER CANAL 550KW		186623.00000	(534)	186623.00000

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	SIDDOWAY SOLAR #486	3,352	186623.00000	(3,352)	186623.00000
23	SIMCO SOLAR #442	2,985	186623.00000	(1,985)	186623.00000
24	SIMCOE SOLAR 2 # 487	7,192	186623.00000	(50,000)	186623.00000
25	SIMCOE SOLAR CENTER #428	37,638	186623.00000	(42,822)	186623.00000
26	SOUTHERN IDAHO SOLID WASTE #501	1,776	186623.00000	(11,000)	186623.00000
27	SUTTON CREEK SOLAR #495	1,457	186623.00000	(10,329)	186623.00000
28	TILLI SOLAR #443	1,599	186623.00000	(599)	186623.00000
29	VALE AIR SOLAR CENTER - GI 412	1,711	186623.00000	12,056	186623.00000
30	VALLEY LANE SOLAR PV1	2,697	186623.00000	(2,697)	186623.00000
31	WEGNER SOLAR #499	329	186623.00000	(1,000)	186623.00000
32	WRIGHT PLACE SOLAR #445	3,463	186623.00000	(2,463)	186623.00000
33	ZEHR SOLAR #497	1,694	186623.00000	(1,694)	186623.00000
34					
35					
36					
37					
38					
39					
40					

Schedule Page: 231 Line No.: 22 Column: d

Amounts represent both reimbursements received and refunds back to the counterparties. Refunds are initiated when the final expenses exceed the intial deposit received.

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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)	17,033,635	363,196	Various	3,216,060	14,180,771
2	IPUC Order #29414-OPUC Order #04-585					
3						
4	ASC 815 Mark to Market (182330 & 182333)	3,960,704	18,595,015	244	17,583,119	4,972,600
5	IPUC Order #28661					
6						
7	FAS 109 Unfunded (182322)	802,188,345	87,385,943	382	14,546,806	875,027,482
8	Accum Deferred Income Noncurrent					
9						
10	PCA Deferral Idaho - IPUC Order #33306	45,412,570	59,429,323	401	55,501,666	49,340,227
11	(Amort period 06/16 thru 05/17) (182323)					
12						
13	PCA Prior Year Deferral Idaho - IPUC Order #33049	12,535,848	34,627,781	401	47,160,880	2,749
14	(Amort period 06/15 thru 05/16) (182324)					
15						
16	Fixed Cost Adjustment (FCA) (182302)	16,811,911	31,393,901	1823	20,266,964	27,938,848
17	IPUC Order #33302 (Amort period 06/16 thru 05/17)					
18						
19	Prior Year FCA IPUC Order #33047 (182309)	6,925,678	25,831,710	400	24,932,619	7,824,769
20	(Amort period 6/15 thru 5/16)					
21						
22	AOCI Impact of Unfunded Post Retirement Liability	903,788	117	2283	2,428,321	-1,524,416
23	IPUC Order #30256 (182306)					
24						
25	Oregon Pension Expense Capitalized (182339)	2,750,366	611,255	4073	94,960	3,266,661
26	OPUC Order #10-064 (Amort period thru 2052)					
27						
28	Deferred Pension Expense Net of Contributions	20,077,507	39,659,896	Various	38,532,812	21,204,591
29	IPUC Order #30333 (182321)					
30						
31	AOCI Impact of Unfunded Pension Liability	263,644,763	4,999,578	2283	15,358,112	253,286,229
32	IPUC Order #30256 (182320)					
33						
34	PCA Unbilled Forecast (182325)	(1,055,813)	19,463,835	401	20,525,175	-2,117,153
35						
36	PCAM Oregon 2008 (182346)	5,534,507	121,552	401	2,424,616	3,231,443
37	OPUC Order #08-238 & #13-439 (Amort 1/14 - 6/17)					
38						
39	PCAM Interest Reserve 2008 (182329)	(568,429)	237,936			-330,493
40	(Amort 1/14 - 6/17)					
41						
42	PCA SBA Unbilled Adj (182326)		33,645,247	401	35,104,595	-1,459,348
43						

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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	FCA Calender Mo Adj IPUC Order (182308)		26,687,947	400	25,631,172	1,056,775
2						
3	Idaho Boardman Decomissioning (182493)	1,217,507	5,674,701	Various	5,478,565	1,413,643
4	IPUC Order #32549 & #32457					
5						
6	Idaho Pension Cash IPUC Order #32248 (182327)	40,816,708	37,690,655	401	17,188,437	61,318,926
7	(Amort period beginning 06/11 thru unknown)					
8						
9	2008 PCAM Unbilled Amort (182356)	(158,302)	1,812,976	401	1,820,146	-165,472
10	(Amort period 1/14 thru 6/17)					
11						
12	Lidar Surveys IPUC Order #32426 (182361)	305,233		402	43,605	261,628
13	(Amort period 01/12 thru 12/21)					
14						
15	PCA Unbilled Amortization (182316)	(2,380,650)	44,612,555	400, 401	43,441,968	-1,210,063
16	(Amort period 06/15 thru 05/16)					
17						
18	Idaho Boardman ARO IPUC Order #29414 (182393)	261,340		4110, 4031	43,557	217,783
19	(Amort period thru 2020)					
20						
21	Langley Revenue Accrual IPUC Order #12-226 (182398)	941,957	75,471			1,017,428
22						
23	Other RA-PS&I Shoshone Order #29904 (182368)		800,373	401	133,395	666,978
24						
25	RA-OATT Deferral-IPUC Order #33313 (182350)		1,083,701			1,083,701
26						
27	RA-OR CUB Fund Amort 15-399 (182386)		272,714			272,714
28	(Amort period 1/16 thru 5/17)					
29						
30	RA-SIEMENS LTP DEF RB 33420 (182410)		11,632,907			11,632,907
31	(Amort period 1/16 thru 12/42)					
32						
33	RA-SIEMENS LTP RB 33420 (182411)		17,358,636			17,358,636
34	(Amort period 1/16 thru 12/42)					
35						
36	RA-SIEMENS LTP DEF RB 15-387 (182412)		446,876			446,876
37	(Amort period 1/16 thru 12/42)					
38						
39	RA-SIEMENS LTP RB 15-387 (182413)		786,315			786,315
40	(Amort period 1/16 thru 12/42)					
41						
42	Bennett Mtn Maintenance IPUC ORder #32426	74,887		402	74,887	
43	(Amort period 01/12 thru 12/15) (182379)					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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	OATT Revenue Deferred Reserve (182336)	286,732			286,732	
2	IPUC Order #30940 (Amort period 6/12 thru 5/15)					
3						
4	Oregon DSM Rider - (182405)		4,482,485	Various		4,482,485
5	Advice #05-03					
6						
7	Minor Items (36)	302,932	312,390	Various	529,414	85,908
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43						
44	**TOTAL :**	1,237,823,724	510,096,987		392,348,583	1,355,572,128

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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 Credit Facility(186025)	669,396	1,716,012	165, 431	1,340,926	1,044,482
2	(Amort period 11/16 thru 11/20)					
3						
4	Prepaid Service Contract	1,659,405	556,171	Various	1,461,732	753,844
5	Long Term Portion (186052)					
6						
7	Long Term (186121)	1,130,749		2282,401	61,090	1,069,659
8	Workers Compensation					
9						
10	Prepaid ROW (186160)	425,944		401	42,970	382,974
11	Rents/Easements Long Term					
12						
13	Long-Term Portfolio (186255)	1,791,148	5,070,889	165, 402	5,768,411	1,093,626
14						
15	OATT Reserve (186350)			400	1,083,701	-1,083,701
16						
17	Advance Prepaid (186709)	1,241,610		151	71,478	1,170,132
18	Coal Royalties					
19						
20	Stable Value Life (186719)		30,004,992			30,004,992
21						
22	Security Plan (186720)	20,059,079	324,769	143,4262	5,613,855	14,769,993
23	Net Insurance Asset					
24						
25	American Falls Bond Ref(186722)	147,948		401	14,553	133,395
26	(Amort Period 04/00 thru 02/25)					
27						
28	Retiree Medical-COLI (186726)	3,834,224	1,128,996	143,4262	1,171,972	3,791,248
29						
30	American Falls Water Rights	10,506,922		401	1,042,009	9,464,913
31	(amort 01/06 - 02/25) (186727)					
32						
33	Shelf Registration (186732)	160,469	2,416,222	181	2,576,691	
34						
35	Milner Bond Guarantee (186734)	3,190,909		253	1,063,636	2,127,273
36	(Amort 02/07 - 2/17)					
37						
38	American Falls - Bond Refinance	487,991		401	47,999	439,992
39	(Amort through 02/25) (186770)					
40						
41	Power Plant - Bridger (186780)	254,793		401	127,396	127,397
42	(Amort thru 06/14 thru 12/16)					
43						
44	Bridger Coal Study (186781)		3,932,864	107, 401	2,527,077	1,405,787
45						
46	Minor Items (3)	4,126	2,777,223	Various	2,776,060	5,289
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	45,564,713				66,701,295

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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)	97,597,101	83,181,338
6			
7	Other (See footnote)	169,747,033	163,213,808
8	TOTAL Electric (Enter Total of lines 2 thru 7)	267,344,134	246,395,146
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	21,759,450	23,793,249
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	289,103,584	270,188,395

Notes

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

	Beginning Balance	Ending Balance
Prov for Rate Refund-HC Relicensing (AFUDC)	28,529,481	34,282,231
Regulatory Asset-Non Current	18,067,486	-
Deferred Idaho ITC	17,378,549	19,624,338
VEBA-Post Retirement Benefits	10,617,384	11,343,166
Incentive Deferral-Profit Sharing-Not in Rates	5,085,262	3,814,372
Stock Based Compensation-FAS 123R	3,782,196	3,813,934
Revenue Sharing	3,127,266	1,235,198
Pension Expense-Oregon	2,488,771	3,008,600
Rate Case Disallowance	2,273,741	2,273,741
Regulatory Liability-Current	1,918,442	-
Construction Advances	1,016,324	1,637,625
Valmy Union Pacific Contract	919,072	-
Asset Retirement Obligation (ARO)	865,690	1,171,048
M & E Reserve	592,049	-
Postretirement Benefits-FAS 112	568,869	486,873
Bridger Revenue Deferral	316,603	316,603
Executive Deferred Compensation	54,988	39,761
Deferred GBC Federal	31,500	31,500
USBR-American Falls O&M Costs Settlement	-	138,920
Non-VEBA Pension and Benefits	(36,572)	(36,572)
Total Other Electric	97,597,101	83,181,338

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

	Beginning Balance	Ending Balance
Pension-FAS 158	103,071,920	99,022,251
Regulatory Asset-FAS 109	50,814,726	51,130,605
Minimum Pension Liability	15,507,051	13,656,923
Postretirement Plan-FAS 158	353,336	(595,971)
Total Other	169,747,033	163,213,808

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

	Beginning Balance	Ending Balance
Senior Management Security Plan	21,402,608	23,635,408
Micron CIAC-Depr Timing Diff	336,836	153,366
Meridian Gold CIAC-Depr Timing Diff	20,006	4,475
Total Non Electric	21,759,450	23,793,249

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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	04/15/2016	End of 2015/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	04/15/2016	End of 2015/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	04/15/2016	End of 2015/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		
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9		
10	Explanation of Changes during the year:	
11		
12		
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21		
22	TOTAL	2,096,925

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/Q4

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Account 221:		
2	First Mortgage Bonds:		
3	4.50% Series due 2020	130,000,000	1,190,698
4			234,601 D
5			
6	5.50% Series due 2033	70,000,000	728,701
7			36,400 D
8			
9	6.15% Series Due 2019	100,000,000	1,034,909
10			184,949 D
11			
12	3.40% Series due 2020	100,000,000	1,159,871
13			498,864 D
14			
15	5.30% Series Due 2035	60,000,000	408,411 D
16			3,802,019
17			
18	4.00% 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	1,877,045,000	31,181,894

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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
				1,747,472,273	83,055,805	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	04/15/2016	End of 2015/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			
9	Humboldt Variable due 2024	49,800,000	1,697,856
10			
11	Sweetwater Variable due 2026	116,300,000	3,026,122
12			
13	2.50% Series due 2023	75,000,000	648,267
14			371,854 D
15			
16	6.025 % Series Due 2018	120,000,000	1,630,120
17			
18	4.30% Series Due 2042	75,000,000	802,240
19			49,417 D
20			
21	2.95% Series Due 2022	75,000,000	708,490
22			127,607 D
23			
24	3.68% Series Due 2045	250,000,000	2,559,510
25			1,715,000 D
26			
27	Subtotal Account 221	1,845,460,000	31,181,894
28			
29	Account 222 - Reaquired Bonds		
30			
31	Account 223: Advances for Associated Companies		
32			
33	TOTAL	1,877,045,000	31,181,894

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.
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	14,841	7
						8
10/22/03	12/01/24	11/01/03	12/01/24	49,800,000	2,564,700	9
						10
10/3/06	7/15/26	10/3/06	7/15/26	116,300,000	6,105,750	11
						12
4/8/2013	4/1/2023	4/8/2013	4/1/2023	75,000,000	1,875,000	13
						14
						15
7/10/08	7/15/18	7/10/08	7/15/08		2,249,333	16
						17
4/13/12	4/1/42	4/13/12	4/1/42	75,000,000	3,225,000	18
						19
						20
4/13/12	4/1/22	4/13/12	4/1/22	75,000,000	2,212,500	21
						22
						23
3/6/15	3/1/45	3/6/15	3/1/45	250,000,000	7,477,431	24
						25
						26
				1,725,460,000	83,055,805	27
						28
						29
						30
						31
						32
				1,747,472,273	83,055,805	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	04/15/2016	End of 2015/Q4

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

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

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Account 224:		
2	Bond Guarantee - American Falls	19,885,000	
3	Note Guarantee - Milner Dam	11,700,000	
4	Subtotal Account 224	31,585,000	
5			
6			
7			
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32			
33	TOTAL	1,877,045,000	31,181,894

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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
04/26/00	2/1/25			19,885,000		2
02/10/92				2,127,273		3
				22,012,273		4
						5
						6
						7
						8
						9
						10
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						31
						32
				1,747,472,273	83,055,805	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	04/15/2016	End of 2015/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)	190,983,483
2		
3		
4	Taxable Income Not Reported on Books	
5		34,015,846
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		-2,121,812
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		29,665,225
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		168,047,554
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	25,164,738
28	Show Computation of Tax:	
29	Tenative Federal Tax @ 35%	8,807,658
30		
31		
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43		
44		

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

4005-AVOIDED COST	7,692,969
4003-CONSTRUCTION ADVANCES	1,775,147
4013-CIAC - TAXABLE - ACCT 107	(5,362,106)
4021-ENGINEERING FEES - TAXABLE - ACCT 107	(109,771)
4024-RENEWABLE ENERGY CERTIFICATES (REC) SALES	451,208
4506-MERIDIAN GOLD CIAC - DEPR TIMING DIFF - NON-OP	(39,726)
4507-MICRON CIAC - DEPR TIMING DIFF - NON-OP	(469,295)
GAIN ON PAC LIKE KIND EXCHANGE	13,052,859
GAIN ON SALE OF SPARE PARTS TO SIEMENS	17,024,561
Total	**34,015,846**

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Total Federal and State taxes deducted on books	**45,111,128**
5001-BAD DEBT EXPENSE	(2,022,198)
5024-NON-DEDUCTIBLE MEALS	500,000
5504-NON-DEDUCTIBLE POLITICAL EXPENSES	1,109,555
5022-263A CAPITALIZED OVERHEADS	(25,000,000)
5070-INCENTIVE DEFERRAL-CRI & RELIABILITY-INCLUDED IN RATES	534,181
5010-POSTEMPLOYMENT BENEFITS-SFAS112	(209,735)
5023-PENSION EXPENSE	(21,846,287)
5035-PCA EXPENSE DEFERRAL	9,955,542
5046-EXECUTIVE DEFERRED COMP - ST	(32,425)
5047-EXECUTIVE DEFERRED COMP - LT	(6,524)
5053-STOCK BASED COMPENSATION - FAS 123R	80,979
5058-FIXED COST ADJUSTMENT	(13,082,804)
5060-OREGON - PCAM	2,072,297
5061-PENSION EXPENSE - OREGON	1,329,658
5065-VALMY UNION PACIFIC CONTRACT	(2,350,868)
5067-ASSET RETIREMENT OBLIGATION (ARO)	781,066
5069-M & E RESERVE	(1,514,386)
5071-INCENTIVE DEFERRAL-PROFIT SHARING-NOT IN RATES	(3,250,774)
5503-EDC - UNREALIZED GAIN/LOSS FROM RABBI TRUST	8,566
5505-SMSP - NET	5,711,217
Total	**(2,121,812)**

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

7501-REVERSE EQUITY EARNINGS OF SUBSIDIARIES	6,659,942
7509-SMSP - INSURANCE PROCEEDS	1,286,474
7502-ALLOWANCE FOR OFUDC	21,785,246
7503-ALLOWANCE FOR BFUDC	10,043,775
7010-PROV FOR RATE REFUND - HC RELICENSING (AFUDC)	(14,714,797)
7011-OATT REVENUE DEFICIENCY	(286,732)
7012-REVENUE SHARING	4,839,667
7013-LANGLEY REVENUE ACCRUAL	51,650
Total	**29,665,225**

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

8025-MANUFACTURING DEDUCTION	2,776,466
8034-REMOVAL COSTS	13,735,582
8042-GAIN/LOSS ON REACQUIRED DEBT	16,931,184

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8073-REPAIRS DEDUCTION	82,000,000
8077-PREPAID INSURANCE & OTHER EXPENSES	256,232
8001-VEBA - POST RETIREMENT BENEFITS	(1,926,786)
8020-CONSERVATION EXPENSES	638,796
8059-SOFTWARE - LABOR COSTS DEDUCTED - ACCT 107	1,000,000
8072-RELICENSING - LABOR COSTS DEDUCTED - ACCT 107	2,800,000
8009-DEPR TIMING DIFF - OPERATING - FEDERAL	42,953,555
STATE INCOME TAX DEDUCTED ON FEDERAL RETURN	6,882,525
Total	**168,047,554**

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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	-17,861,172		13,222,719	546,919	
3	Social Security - (FOAB)	-1,179		14,633,862	14,633,217	
4	Unemployment			93,143	93,143	
5	Subtotal Federal	-17,862,351		27,949,724	15,273,279	
6						
7	State of Idaho:					
8	Property	9,028,370		21,603,531	21,196,819	-15
9	Non-Operating	11,508		19,188	20,350	
10	Income	-2,913,887		5,454,898	2,799,259	
11	KWH	86,152		1,465,259	1,458,487	
12	Unemployment			557,293	557,293	
13	Regulatory Commission			2,842,553	2,842,553	
14	Business License - Sho Ban			150	150	
15	Subtotal Idaho	6,212,143		31,942,872	28,874,911	-15
16						
17	State of Oregon					
18	Property		1,435,643	2,974,336	3,135,491	
19	Non-Operating Property		918	1,867		
20	Income	-171,566		268,067	203,277	
21	Regulatory Commission			206,569	206,569	
22	Unemployment			52,232	53,089	
23	Franchise	205,949		824,997	833,458	
24	Subtotal Oregon	34,383	1,436,561	4,328,068	4,431,884	
25						
26	State of Montana:					
27	Property	161,411		339,510	331,295	
28	Subtotal Montana	161,411		339,510	331,295	
29						
30	State of Nevada:					
31	Property		502,346	1,063,273	1,097,236	
32	Subtotal Nevada		502,346	1,063,273	1,097,236	
33						
34	State of Wyoming					
35	Corporate License			4,843	4,843	
36	Property	802,464		1,627,460	1,614,781	
37	Subtotal Wyoming	802,464		1,632,303	1,619,624	
38						
39						
40						
41	TOTAL	-10,635,253	1,938,907	51,966,919	51,674,868	5,823

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
-5,185,372		12,593,365			629,354	2
-534		14,633,862				3
		93,143				4
-5,185,906		27,320,370			629,354	5
						6
						7
9,435,081		21,602,678			853	8
10,346					19,188	9
-258,247		5,656,832			-201,934	10
92,925		1,465,259				11
		557,293				12
		2,842,553				13
		150				14
9,280,105		32,124,765			-181,893	15
						16
						17
	1,596,798	2,830,399			143,937	18
	948				1,867	19
-106,776		277,503			-9,436	20
		206,569				21
-857		52,232				22
197,487		824,997				23
89,854	1,597,746	4,191,700			136,368	24
						25
						26
169,627		339,510				27
169,627		339,510				28
						29
						30
	536,309	1,063,273				31
	536,309	1,063,273				32
						33
						34
		4,843				35
815,142		1,627,460				36
815,142		1,632,303				37
						38
						39
						40
5,192,418	2,134,055	51,387,776			579,143	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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	State of Washington					
2	Property			610	610	
3	Subtotal Washington			610	610	
4						
5	Other States Income	-17,398		47,089	-1,825	
6	Payroll Tax Credit			-15,336,530		
7	Canada GST tax	34,095			47,854	5,838
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
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36						
37						
38						
39						
40						
41	TOTAL	-10,635,253	1,938,907	51,966,919	51,674,868	5,823

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
		610				2
		610				3
						4
31,516		51,775			-4,686	5
		-15,336,530				6
-7,920						7
						8
						9
						10
						11
						12
						13
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						40
5,192,418	2,134,055	51,387,776			579,143	41

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

```
Account 409.2        $     353,061
Account 234.020         (1,485,757)
Account 182.410           1,762,050
                     -------------
Total                $     629,354
                     =============
```

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

Miscellaneous Rounding

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

```
Account 107          $         853
```

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

```
Account 408.2        $      19,188
```

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

```
Account 409.2        $     65,362
Account 234.020          (267,296)
                     ------------
Total                $  (201,934)
                     ============
```

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

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Account 107          $   143,937
```

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

```
Account 408.2        $     1,867
```

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

```
Account 409.2        $     4,155
Account 234.020          (13,591)
                     ------------
Total                $    (9,436)
                     ============
```

Schedule Page: 262.1 Line No.: 5 Column: l

```
Account 409.2        $        (155)
Account 234.020             (4,531)
                     -------------
Total                $      (4,686)
                     =============
```

Schedule Page: 262.1 Line No.: 6 Column: i

This amount is an offset to lines 3, 4, 12 and 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: 262.1 Line No.: 7 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	04/15/2016	End of 2015/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%	434,199				56,428	
4	7%						
5	10%	19,699,576				1,383,541	
6	11%	1,161,824				26,029	
7	Other- State	57,867,232	411.4	3,455,060	411.4	1,496,963	
8	TOTAL	79,162,831		3,455,060		2,962,961	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	Line 6 Col A 11%						
11							
12	State of Idaho	57,867,232	411.4	3,455,060	411.4	1,496,963	
13							
14							
15							
16							
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19							
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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	04/15/2016	End of 2015/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
377,771	7.69		3
			4
18,316,035	14.24		5
1,135,795	44.64		6
59,825,329	38.66		7
79,654,930			8
			9
			10
			11
59,825,329			12
			13
			14
			15
			16
			17
			18
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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	04/15/2016	End of 2015/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	Point to Point Trans Study(253201)	1,287,950	186, 242	8,854,688	9,625,463	2,058,725
2						
3	FTV (253202)	2,866,666	400	400,000		2,466,666
4	(Amort Period Mar 1998-Feb 2023)					
5						
6	Sho Ban Trans ROW (253480)	202,500	242	15,000		187,500
7	(Amort Period Jan 2005-Dec 2027)					
8						
9	Operations Accrual (253550)	1,271,388	232, 401	66,776	88,641	1,293,253
10	(amort period 1 year for dues)					
11						
12	Milner Falling Water (253953)	667,185	186	1,190,450	1,237,096	713,831
13	Amort Period (Feb 1992 - Feb 2017)					
14						
15	Postretirement Benefits (253960)	1,455,093	253, 401	1,455,093	1,245,358	1,245,358
16						
17	Directors Deferred Compensation	3,883,100	131	417,959	324,206	3,789,347
18	(253980-253999)					
19						
20	Minor Items (1) 253042	1,760	Various	59,403	60,961	3,318
21						
22						
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47	TOTAL	11,635,642		12,459,369	12,581,725	11,757,998

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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	451,117,692	41,997,682	18,235,837
3	Gas			
4	Other			
5	TOTAL (Enter Total of lines 2 thru 4)	451,117,692	41,997,682	18,235,837
6	Non-Operating Property			
7	Other - Regulatory Asset	797,512,669		
8	Like Kind Exchange- Reclass No			
9	TOTAL Account 282 (Enter Total of lines 5 thru	1,248,630,361	41,997,682	18,235,837
10	Classification of TOTAL			
11	Federal Income Tax	1,071,548,840	41,671,931	18,118,546
12	State Income Tax	177,081,521	325,751	117,291
13	Local Income Tax			

NOTES

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	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
	5,706,531	282.111	69,255			469,103,751	2
							3
							4
	5,706,531		69,255			469,103,751	5
							6
				182	77,514,814	875,027,483	7
5,706,531				282100	69,255	5,775,786	8
5,706,531	5,706,531		69,255		77,584,069	1,349,907,020	9
							10
5,706,531	5,706,531		69,255		61,569,691	1,156,602,661	11
					16,014,378	193,304,359	12
							13

NOTES (Continued)

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

Line No.	Account (a)	2015 Beginning Balance b	Changes during Year: DR to 410.1 c	Changes during Year: CR to 411.1 d	Adjustments Debits: CR to 411.2 f	Adjustments Debits: Acct. credited g	Adjustments Debits: Amount h	2015 Ending Balance k
Line 2:	Depreciation Timing Diff-Operating	439,778,212	37,566,234	18,176,936	5,706,531	282.111	69,255	453,391,724
	Intangible-Labor Costs Deducted-Acct 107	17,382,911	965,708					18,348,619
	CIAC-Taxable-Acct 107	(6,010,733)	2,722,934					(3,287,799)
	Valmy Capitalized Items	121,766		58,206				63,560
	Software-Labor Costs Deducted-Acct 107	347,096	704,386					1,051,482
	Engineering Fees-Taxable-Acct 107	(501,560)	38,420	695				(463,835)
	TOTAL Line 2	451,117,692	41,997,682	18,235,837	5,706,531		69,255	469,103,751

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Other Electric -- See Note	74,155,896	15,289,514	25,283,305
4				
5				
6				
7				
8	Other -- See Note	103,425,257		
9	TOTAL Electric (Total of lines 3 thru 8)	177,581,153	15,289,514	25,283,305
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other -- See Note	851,124		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	178,432,277	15,289,514	25,283,305
20	Classification of TOTAL			
21	Federal Income Tax	149,678,643	12,825,671	21,209,003
22	State Income Tax	28,753,634	2,463,843	4,074,302
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/Q4

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

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

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
						64,162,105	3
							4
							5
							6
							7
		190	4,998,975			98,426,282	8
			4,998,975			162,588,387	9
							10
							11
							12
							13
							14
							15
							16
							17
6,080	538,968					318,236	18
6,080	538,968		4,998,975			162,906,623	19
							20
5,100	452,116		4,193,411			136,654,884	21
980	86,852		805,564			26,251,739	22
							23

NOTES (Continued)

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

Line No.	Account (a)	2015 Beginning Balance b	Changes during Year DR to 410.1 c	CR to 411.1 d	2015 Ending Balance k
Line 3:	Pension Expense	18,934,259	8,729,744		27,664,003
	PCA Expense	21,311,448		3,892,119	17,419,329
	Conservation Expenses	1,789,468	249,737	305,813	1,733,392
	Fixed Cost Adjustment	9,280,211	5,114,722		14,394,933
	Regulatory Asset-Current	18,067,486		18,067,486	(0)
	Oregon PCAM	1,942,270		810,947	1,131,323
	Regulatory Liability-Non Current	1,918,442		1,918,442	0
	Boardman Decommission	484,201			484,201
	Oregon Excess Power Costs	(61,888)		0	(61,888)
	OATT Revenue Deficiency	112,098		112,098	0
	Renewable Energy Certificates (REC) Sales	(228,084)	1,150,343	176,400	745,859
	Langley Revenue Accrual	350,781	20,193		370,974
	2011 LIDAR Surveys Deferral	119,331			119,331
	Bennett Mtn Maint Deferral	29,277		0	29,277
	Intervenor Funding Orders	121,344	0		121,344
	OPUC Grid West Loans	925	0	0	925
	Emission Allowances	3,722	5,380		9,102
	Delivery Accruals	(19,395)	19,395		(0)
	TOTAL Line 3	74,155,896	15,289,514	25,283,305	64,162,105

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

Line No.	Account (a)	2015 Beginning Balance b	Changes during Year DR to 410.1 c	CR to 411.1 d	DR to 410.2 e	CR to 411.2 f	Adjustments Debits Acct. credited g	Amount h	2015 Ending Balance k
Line 8:	Pension-FAS 158	103,071,921					190	4,049,669	99,022,252
	Postretirement Plan-FAS 158	353,336					190	949,306	(595,970)
	TOTAL Line 8	103,425,257	0	0	0	0		4,998,975	98,426,282

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

Line No.	Account (a)	2015 Beginning Balance b	Changes during Year DR to 410.1 c	CR to 411.1 d	DR to 410.2 e	CR to 411.2 f	Adjustments Debits Acct. credited g	Amnt h	2015 Ending Balance k
Line 18:	EDC-Unrealized Gain/Loss From Rabbit Trust	543,030				538,610			4,420
	SMSP-Unrealized Gain/Loss From Rabbi Trust	(41,951)							(41,951)
	Royalty Income	349,687			5,721				355,408
	Oregon Non-Op Prop Tax Adj	358			359	358			359
	TOTAL Line 18	851,124	0	0	6,080	538,968		0	318,236

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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)	1,817,027	175	6,301,317	4,763,049	278,759
2	IPUC Order #28661					
3						
4	FAS 133 - Market to Market - (254203)	63,322	175	378,924	442,082	126,480
5	IPUC Order # 28661					
6						
7	Unfunded Accum Def Income Tax (254966)	50,814,726	Various	378,735	694,614	51,130,605
8						
9	Idaho DSM Rider (254201)	(782,231)	Various	37,911,476	45,247,781	6,554,074
10	Order #29026					
11						
12	Oregon Solar Pilot - (254005)	2,400,864	Various	554,880	1,194,533	3,040,517
13	Order #10-198					
14						
15	Green Tags Oregon (254415)	132,831	1823, 254	137,928	78,074	72,977
16	Order #11-086					
17						
18	Regulatory Unfunded Accum Def Income Tax (254419)	4,675,677	1823	5,341,917	666,240	
19						
20	Revenue Sharing (254101)	7,999,145	1823, 400	11,026,832	6,187,165	3,159,478
21	IPUC Order #33149					
22						
23	BPA Credit Residential Idaho (254401)	643,903	142	2,481,690	3,862,855	2,025,068
24	Advice # 11-03 (ID) #11-15 (OR)					
25						
26	WAQC Carryover (254901)	112,536	401	112,536	48,688	48,688
27	IPUC Order #29505					
28						
29	Bridger Depreciation #12-296 -(254800)	809,830			321,839	1,131,669
30						
31	Oregon DSM Rider - (254202)	(3,907,536)			3,907,536	
32	Advice #05-03					
33						
34	Minor Items (7)	63,175	Various	593,846	674,011	143,340
35						
36						
37						
38						
39						
40						
41	TOTAL	64,843,269		65,220,081	68,088,467	67,711,655

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	512,068,335	500,194,726
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	466,541,569	453,982,593
5	Large (or Ind.) (See Instr. 4)	182,254,287	182,675,224
6	(444) Public Street and Highway Lighting	4,039,381	4,133,623
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,164,903,572	1,140,986,166
11	(447) Sales for Resale	30,887,261	77,164,887
12	TOTAL Sales of Electricity	1,195,790,833	1,218,151,053
13	(Less) (449.1) Provision for Rate Refunds	13,865,518	18,348,408
14	TOTAL Revenues Net of Prov. for Refunds	1,181,925,315	1,199,802,645
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	4,119,479	3,780,239
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	24,852,979	23,695,291
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	31,174,302	27,734,886
22	(456.1) Revenues from Transmission of Electricity of Others	24,129,372	22,627,916
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	84,276,132	77,838,332
27	TOTAL Electric Operating Revenues	1,266,201,447	1,277,640,977

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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
4,977,176	4,965,076	432,275	425,036	2
				3
6,059,428	5,877,580	85,560	84,425	4
3,195,786	3,217,070	119	116	5
32,103	32,641	2,592	2,380	6
				7
				8
				9
14,264,493	14,092,367	520,546	511,957	10
1,254,136	2,220,419			11
15,518,629	16,312,786	520,546	511,957	12
				13
15,518,629	16,312,786	520,546	511,957	14

Line 12, column (b) includes $ 7,691,485 of unbilled revenues.
Line 12, column (d) includes 97,949 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)	$ 3,991,239
Misc. Under $250,000	128,240
Total Account 451	$ 4,119,479

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

This amount consists of:

Alternate Distribution Service	$ 321,995
DSM Activity	30,531,891
Misc. Under $250,000	320,416
Total Account 456	$ 31,174,302

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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	04/15/2016	End of 2015/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	4,909,951	485,187,406	430,891	11,395	0.0988
3	03 - Residential Master Meter	3,915	369,431	22	177,955	0.0944
4	05 - Residential - TOD	22,760	2,173,445	1,362	16,711	0.0955
5	15 - Dusk to dawn lighting	2,643	647,369			0.2449
6	Unbilled Revenues	37,907	3,804,720			0.1004
7	Other Revenues		19,885,964			
8	Total 440	4,977,176	512,068,335	432,275	11,514	0.1029
9						
10	442-Commercial & Industrial Sales					
11	07 - General service	148,554	18,030,960	30,568	4,860	0.1214
12	09P - General service	468,026	30,263,440	210	2,228,695	0.0647
13	09S - General service	3,310,465	242,228,577	33,750	98,088	0.0732
14	09T - General service	5,919	427,302	4	1,479,750	0.0722
15	15 - Dusk to Dawn Light	4,161	740,435			0.1779
16	19P - Uniform rate contracts	2,219,894	128,442,280	112	19,820,482	0.0579
17	19S - Uniform rate contracts	6,409	407,625	1	6,409,000	0.0636
18	19T - Uniform rate contracts	133,079	7,770,633	3	44,359,667	0.0584
19	24S - Irrigation Pumping	2,046,290	162,170,953	20,151	101,548	0.0793
20	40 - General service	10,300	887,261	877	11,745	0.0861
21	Special Contracts	842,100	43,182,373	3	280,700,000	0.0513
22	Commercial & Industrial Unbill	60,017	3,882,851			0.0647
23	Other Revenues		10,361,166			
24	Total 442	9,255,214	648,795,856	85,679	108,022	0.0701
25						
26	444 - Public Street Lighting:					
27	40 - General service	1,120	96,700	456	2,456	0.0863
28	41 - Street lighting	28,127	3,696,413	1,607	17,503	0.1314
29	42 - Traffic control lighting	2,832	178,272	529	5,353	0.0629
30	Unbilled	24	3,915			0.1631
31	Other Revenues		64,081			
32	Total 444	32,103	4,039,381	2,592	12,385	0.1258
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	14,166,544	1,157,212,087	520,546	27,215	0.0817
42	Total Unbilled Rev.(See Instr. 6)	97,949	7,691,485	0	0	0.0785
43	TOTAL	14,264,493	1,164,903,572	520,546	27,403	0.0817

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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	ADM Investor Services, Inc.	OS	-	n/a	n/a	n/a
2	Arizona Public Service Co.	SF	WSPP	n/a	n/a	n/a
3	Avista Corp.	SF	WSPP	n/a	n/a	n/a
4	Basin Electric Power Cooperative	SF	WSPP	n/a	n/a	n/a
5	Black Hills Power Inc.	SF	WSPP	n/a	n/a	n/a
6	Black Hills Power Inc.	OS	WSPP	n/a	n/a	n/a
7	Bonneville Power Administration	SF	WSPP	n/a	n/a	n/a
8	BP Energy Company	SF	WSPP	n/a	n/a	n/a
9	Calpine Energy Services, L.P.	SF	WSPP	n/a	n/a	n/a
10	Cargill Power Markets LLC	SF	WSPP	n/a	n/a	n/a
11	Cargill Power Markets LLC	OS	WSPP	n/a	n/a	n/a
12	Cargill Power Markets LLC	OS	ISDA	n/a	n/a	n/a
13	City of Anaheim	SF	WSPP	n/a	n/a	n/a
14	Clatskanie 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) 04/15/2016	Year/Period of Report End of 2015/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
			-861,190	-861,190	1
4,400		64,000		64,000	2
72,813		1,230,085		1,230,085	3
2,118		54,030		54,030	4
845		16,805		16,805	5
150			1,200	1,200	6
32,888		653,025		653,025	7
2,400		62,464		62,464	8
300		4,500		4,500	9
1,810		38,245		38,245	10
2,353			17,690	17,690	11
			1,128,634	1,128,634	12
37,200		919,472		919,472	13
160		3,134		3,134	14
0	0	0	0	0	
1,254,136	0	26,516,513	4,370,748	30,887,261	
1,254,136	**0**	**26,516,513**	**4,370,748**	**30,887,261**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/Q4

SALES FOR RESALE (Account 447)

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	EDF Trading North America, LLC	SF	WSPP	n/a	n/a	n/a
2	Energy Keepers	SF	WSPP	n/a	n/a	n/a
3	Eugene Electric Board	SF	WSPP	n/a	n/a	n/a
4	Exelon Generation Company. LLC	SF	WSPP	n/a	n/a	n/a
5	Grant County Public Utility District #2	SF	WSPP	n/a	n/a	n/a
6	Iberdrola Renewables, Inc.	SF	WSPP	n/a	n/a	n/a
7	Iberdrola Renewables, Inc.	OS	-	n/a	n/a	n/a
8	Iberdrola Renewables, Inc.	OS	WSPP	n/a	n/a	n/a
9	Jeffries Bache	OS	-	n/a	n/a	n/a
10	Los Angeles Department of Water & Power	SF	WSPP	n/a	n/a	n/a
11	Macquarie Energy LLC	OS	ISDA	n/a	n/a	n/a
12	Macquarie Energy LLC	OS	WSPP	n/a	n/a	n/a
13	Morgan Stanley Capital Group Inc.	SF	ISDA	n/a	n/a	n/a
14	Morgan Stanley Capital Group Inc.	OS	ISDA	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) 04/15/2016	Year/Period of Report End of 2015/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
51,000		1,438,760		1,438,760	1
10		220		220	2
3,437		73,384		73,384	3
153,345		3,412,586		3,412,586	4
2,163		50,606		50,606	5
13,600		305,566		305,566	6
			17,113	17,113	7
			16,472	16,472	8
			2,361,474	2,361,474	9
148,400		4,362,200		4,362,200	10
			215,438	215,438	11
			272	272	12
43,627		833,497		833,497	13
401			5,359	5,359	14
0	0	0	0	0	
1,254,136	0	26,516,513	4,370,748	30,887,261	
1,254,136	**0**	**26,516,513**	**4,370,748**	**30,887,261**	

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Morgan Stanley Capital Group Inc.	OS	WSPP	n/a	n/a	n/a
2	Nevada Power Company, dba NVEnergy	SF	WSPP	n/a	n/a	n/a
3	Nevada Power Company, dba NVEnergy	OS	WSPP	n/a	n/a	n/a
4	Nevada Power Company, dba NVEnergy	OS	WSPP	n/a	n/a	n/a
5	NorthWestern Energy	SF	WSPP	n/a	n/a	n/a
6	NorthWestern Energy	OS	WSPP	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	PacifiCorp Inc.	OS	T-7	n/a	n/a	n/a
10	Portland General Electric Company	SF	WSPP	n/a	n/a	n/a
11	Portland General Electric Company	OS	WSPP	n/a	n/a	n/a
12	Portland General Electric Company	OS	T-7	n/a	n/a	n/a
13	Portland General Electric Company	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 Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
			574,949	574,949	1
18,161		299,299		299,299	2
14,846			191,688	191,688	3
			10,766	10,766	4
3,428		68,022		68,022	5
3,375			27,490	27,490	6
9,544		173,862		173,862	7
400			5,600	5,600	8
87			1,805	1,805	9
57,704		1,311,422		1,311,422	10
1,672			26,420	26,420	11
4			72	72	12
			20,130	20,130	13
9,610		119,981		119,981	14
0	0	0	0	0	
1,254,136	0	26,516,513	4,370,748	30,887,261	
1,254,136	**0**	**26,516,513**	**4,370,748**	**30,887,261**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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	Powerex Corp.	OS	WSPP	n/a	n/a	n/a
2	Puget Sound Energy, Inc.	SF	WSPP	n/a	n/a	n/a
3	Puget Sound Energy, Inc.	OS	T-7	n/a	n/a	n/a
4	Rainbow Energy Marketing Corporation	SF	WSPP	n/a	n/a	n/a
5	Seattle City Light	SF	WSPP	n/a	n/a	n/a
6	Seattle City Light	OS	WSPP	n/a	n/a	n/a
7	Shell Energy North America (US), L.P.	SF	WSPP	n/a	n/a	n/a
8	Shell Energy North America (US), L.P.	OS	WSPP	n/a	n/a	n/a
9	Shell Energy North America (US), L.P.	OS	WSPP	n/a	n/a	n/a
10	Sierra Pacific Power Co., dba NV Energy	OS	T-7	n/a	n/a	n/a
11	Snohomish County PUD	SF	WSPP	n/a	n/a	n/a
12	Talen Energy Marketing, LLC	SF	WSPP	n/a	n/a	n/a
13	Talen Energy Marketing, LLC	OS	WSPP	n/a	n/a	n/a
14	Talen Energy Marketing, LLC	OS	WSPP	n/a	n/a	n/a
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
10,358			29,345	29,345	1
14,746		303,898		303,898	2
22			394	394	3
4,200		69,800		69,800	4
11,628		274,040		274,040	5
425			2,825	2,825	6
301,897		6,048,170		6,048,170	7
25			150	150	8
			476,119	476,119	9
58			1,145	1,145	10
1,081		33,752		33,752	11
1,863		31,603		31,603	12
			7,232	7,232	13
350			1,950	1,950	14
0	0	0	0	0	
1,254,136	0	26,516,513	4,370,748	30,887,261	
1,254,136	**0**	**26,516,513**	**4,370,748**	**30,887,261**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/Q4

SALES FOR RESALE (Account 447)

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

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

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
7,511		178,846		178,846	1
50			400	400	2
			1,769	1,769	3
173,226		3,261,545		3,261,545	4
75			1,625	1,625	5
			23,133	23,133	6
34,376		819,694		819,694	7
			38,535	38,535	8
-6			194	194	9
			24,550	24,550	10
					11
					12
					13
					14
0	0	0	0	0	
1,254,136	0	26,516,513	4,370,748	30,887,261	
1,254,136	**0**	**26,516,513**	**4,370,748**	**30,887,261**	

Schedule Page: 310 Line No.: 1 Column: b
ADM Investor Services, Inc Futures Account Document, dated May 5, 2015
Schedule Page: 310 Line No.: 6 Column: b
Non-firm Sales
Schedule Page: 310 Line No.: 11 Column: b
Non-firm Sales
Schedule Page: 310 Line No.: 12 Column: b
ISDA Master Agreement with Cargill Power Markets, LLC dated June 13, 2011
Schedule Page: 310.1 Line No.: 7 Column: b
Iberdrola Renewables, Inc, Capacity Agreement, dated January 16, 2015
Schedule Page: 310.1 Line No.: 8 Column: b
Financial Transmission Losses
Schedule Page: 310.1 Line No.: 9 Column: b
Prudential Bache Commodities (Jeffries Bache), LLC Futures Account Document, dated September 4,2008
Schedule Page: 310.1 Line No.: 11 Column: b
ISDA Master Agreement with Macquarie Energy, LLC dated April 12, 2011
Schedule Page: 310.1 Line No.: 12 Column: b
Financial Transmission Losses
Schedule Page: 310.1 Line No.: 14 Column: b
Non-firm Sales
Schedule Page: 310.2 Line No.: 1 Column: b
Financial Transmission Losses
Schedule Page: 310.2 Line No.: 3 Column: b
Non-firm Sales
Schedule Page: 310.2 Line No.: 4 Column: b
Financial Transmission Losses
Schedule Page: 310.2 Line No.: 6 Column: b
Non-firm Sales
Schedule Page: 310.2 Line No.: 8 Column: b
Non-firm Sales
Schedule Page: 310.2 Line No.: 9 Column: b
Spinning or Operating Reserves
Schedule Page: 310.2 Line No.: 11 Column: b
Non-firm Sales
Schedule Page: 310.2 Line No.: 12 Column: b
Spinning or Operating Reserves
Schedule Page: 310.2 Line No.: 13 Column: b
Financial Transmission Losses
Schedule Page: 310.3 Line No.: 1 Column: b
Non-firm Sales
Schedule Page: 310.3 Line No.: 3 Column: b
Spinning or Operating Reserves
Schedule Page: 310.3 Line No.: 6 Column: b
Non-firm Sales
Schedule Page: 310.3 Line No.: 8 Column: b
Non-firm Sales
Schedule Page: 310.3 Line No.: 9 Column: b
Financial Transmission Losses
Schedule Page: 310.3 Line No.: 10 Column: b
Spinning or Operating Reserves
Schedule Page: 310.3 Line No.: 13 Column: b
Financial Transmission Losses
Schedule Page: 310.3 Line No.: 14 Column: b

Non-firm Sales

Schedule Page: 310.4 Line No.: 2 Column: b

Non-firm Sales

Schedule Page: 310.4 Line No.: 3 Column: b

Financial Transmission Losses

Schedule Page: 310.4 Line No.: 5 Column: b

Non-firm Sales

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

Financial Transmission Losses

Schedule Page: 310.4 Line No.: 8 Column: b

Financial Transmission Losses

Schedule Page: 310.4 Line No.: 9 Column: b

Prior Year Adjustments

Schedule Page: 310.4 Line No.: 10 Column: b

Transmission Penalty Distribution

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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	1,287,887	1,376,709
5	(501) Fuel	131,286,356	156,172,175
6	(502) Steam Expenses	9,791,612	8,741,266
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,262,175	1,599,507
10	(506) Miscellaneous Steam Power Expenses	6,676,269	9,598,723
11	(507) Rents	432,038	530,520
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	150,736,337	178,018,900
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	126,993	277,886
16	(511) Maintenance of Structures	878,071	708,308
17	(512) Maintenance of Boiler Plant	13,861,559	10,923,064
18	(513) Maintenance of Electric Plant	5,412,553	6,044,954
19	(514) Maintenance of Miscellaneous Steam Plant	6,923,251	5,806,415
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	27,202,427	23,760,627
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	177,938,764	201,779,527
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	5,798,402	5,700,460
45	(536) Water for Power	9,070,347	7,316,134
46	(537) Hydraulic Expenses	14,907,949	14,097,825
47	(538) Electric Expenses	1,623,508	1,530,453
48	(539) Miscellaneous Hydraulic Power Generation Expenses	5,675,338	5,732,591
49	(540) Rents	235,266	259,705
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	37,310,810	34,637,168
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	120,335	122,182
54	(542) Maintenance of Structures	1,120,484	1,387,369
55	(543) Maintenance of Reservoirs, Dams, and Waterways	575,444	366,307
56	(544) Maintenance of Electric Plant	2,655,929	2,279,584
57	(545) Maintenance of Miscellaneous Hydraulic Plant	2,860,095	2,554,638
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	7,332,287	6,710,080
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	44,643,097	41,347,248

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	646,633	813,875
63	(547) Fuel	54,944,643	45,068,831
64	(548) Generation Expenses	4,603,907	3,596,219
65	(549) Miscellaneous Other Power Generation Expenses	934,376	905,574
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	61,129,559	50,384,499
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures	363,695	378,067
71	(553) Maintenance of Generating and Electric Plant	71,909	86,516
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	1,270,216	1,391,428
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	1,705,820	1,856,011
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	62,835,379	52,240,510
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	217,596,604	237,121,899
77	(556) System Control and Load Dispatching	2,436	-1,242
78	(557) Other Expenses	20,615,245	25,139,587
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	238,214,285	262,260,244
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	523,631,525	557,627,529
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	4,136,382	4,019,284
84			
85	(561.1) Load Dispatch-Reliability		55,425
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	1,757,323	1,673,701
87	(561.3) Load Dispatch-Transmission Service and Scheduling	1,159,643	926,555
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	21,585	38,422
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	2,633,328	2,458,270
94	(563) Overhead Lines Expenses	967,338	669,240
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	6,279,133	6,081,299
97	(566) Miscellaneous Transmission Expenses	2,365	18,274
98	(567) Rents	3,084,849	3,284,850
99	TOTAL Operation (Enter Total of lines 83 thru 98)	20,041,946	19,225,320
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	157,051	169,505
102	(569) Maintenance of Structures	12,690	26,645
103	(569.1) Maintenance of Computer Hardware	23,408	9,454
104	(569.2) Maintenance of Computer Software	867,398	960,142
105	(569.3) Maintenance of Communication Equipment	29,123	42,031
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	3,286,329	3,702,550
108	(571) Maintenance of Overhead Lines	2,935,312	3,198,420
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant		1,593
111	TOTAL Maintenance (Total of lines 101 thru 110)	7,311,311	8,110,340
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	27,353,257	27,335,660

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	4,289,300	4,028,859
135	(581) Load Dispatching	3,897,253	3,643,133
136	(582) Station Expenses	1,339,544	1,180,321
137	(583) Overhead Line Expenses	3,968,009	3,138,798
138	(584) Underground Line Expenses	2,889,346	2,525,008
139	(585) Street Lighting and Signal System Expenses	87,956	76,902
140	(586) Meter Expenses	4,769,220	4,424,696
141	(587) Customer Installations Expenses	784,157	694,859
142	(588) Miscellaneous Expenses	6,041,032	5,788,865
143	(589) Rents	262,071	466,127
144	TOTAL Operation (Enter Total of lines 134 thru 143)	28,327,888	25,967,568
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	10,627	16,451
147	(591) Maintenance of Structures		
148	(592) Maintenance of Station Equipment	3,630,618	3,950,824
149	(593) Maintenance of Overhead Lines	14,203,471	13,906,165
150	(594) Maintenance of Underground Lines	604,456	630,375
151	(595) Maintenance of Line Transformers	36,603	148,125
152	(596) Maintenance of Street Lighting and Signal Systems	486,847	531,740
153	(597) Maintenance of Meters	767,987	735,448
154	(598) Maintenance of Miscellaneous Distribution Plant	289,620	418,635
155	TOTAL Maintenance (Total of lines 146 thru 154)	20,030,229	20,337,763
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	48,358,117	46,305,331
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	484,451	503,846
160	(902) Meter Reading Expenses	1,843,348	1,698,642
161	(903) Customer Records and Collection Expenses	15,508,388	16,630,398
162	(904) Uncollectible Accounts	3,319,967	6,715,796
163	(905) Miscellaneous Customer Accounts Expenses	395	95
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	21,156,549	25,548,777

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	807,713	593,673
168	(908) Customer Assistance Expenses	37,606,989	34,149,782
169	(909) Informational and Instructional Expenses	424,680	374,524
170	(910) Miscellaneous Customer Service and Informational Expenses	735,552	696,365
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	39,574,934	35,814,344
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses	79,720	
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	79,720	
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	73,062,858	73,163,837
182	(921) Office Supplies and Expenses	14,719,911	17,437,094
183	(Less) (922) Administrative Expenses Transferred-Credit	26,120,468	27,257,584
184	(923) Outside Services Employed	8,177,858	4,705,146
185	(924) Property Insurance	3,382,607	3,461,411
186	(925) Injuries and Damages	6,644,800	6,125,055
187	(926) Employee Pensions and Benefits	45,004,540	61,971,169
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	3,616,257	3,457,838
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	618,107	453,160
192	(930.2) Miscellaneous General Expenses	5,444,853	4,907,415
193	(931) Rents	2,000	176
194	TOTAL Operation (Enter Total of lines 181 thru 193)	134,553,323	148,424,717
195	Maintenance		
196	(935) Maintenance of General Plant	5,817,078	7,508,482
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	140,370,401	155,933,199
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	800,524,503	848,564,840

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	AgPower Jerome / Double A Digester	LU	-	N/A	N/A	N/A
2	Allan Ravenscroft/Malad River	LU	-	.488Mw		
3	Baker City Hydro	LU		N/A	N/A	N/A
4	Bannock County, Idaho	LU	-	N/A	N/A	N/A
5	Bennett Creek Wind Farm	LU	-	N/A	N/A	N/A
6	Bettencourt DryCreek Biofactory	LU	-	N/A	N/A	N/A
7	Big Sky West Dairy Digester	LU	-	N/A	N/A	N/A
8	Big Wood Canal Company		-			
9	Black Canyon #3	LU	-	N/A	N/A	N/A
10	Jim Knight	LU	-	N/A	N/A	N/A
11	Sagebrush	LU	-	N/A	N/A	N/A
12	Black Canyon Bliss	LU		N/A	N/A	N/A
13	Blind Canyon Hydro	LU	-	N/A	N/A	N/A
14	Branchflower/Trout Company	LU	-	N/A	N/A	N/A
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
25,577				2,160,857		2,160,857	1
1,401			155,672	57,887		213,559	2
278				10,695		10,695	3
8,705				434,633		434,633	4
35,670				2,210,264		2,210,264	5
10,600				790,198		790,198	6
8,739				545,582		545,582	7
							8
257				18,420		18,420	9
951				69,799		69,799	10
832				62,070		62,070	11
42				1,094		1,094	12
3,972				184,552		184,552	13
688				49,396		49,396	14
3,788,934	276,510	162,239	2,815,124	204,436,381	10,345,099	217,596,604	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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	Burley Butte Wind Park	LU	-	N/A	N/A	N/A
2	Bypass Limited	LU	-	N/A	N/A	N/A
3	Camp Reed Wind Park	LU	-	N/A	N/A	N/A
4	Cargill Inc./B6 Anaerobic Digester	LU	-	N/A	N/A	N/A
5	Cassia Gulch Wind Park	LU		N/A	N/A	N/A
6	Cassia Wind Farm	LU	-	N/A	N/A	N/A
7	City of Cove, Oregon / Mill Creek	LU	-	N/A	N/A	N/A
8	City of Hailey	LU	-	N/A	N/A	N/A
9	City of Pocatello	LU	-	N/A	N/A	N/A
10	Clear Springs Food Inc.	LU	-	N/A	N/A	N/A
11	Clifton E. Jenson/Birch Creek	LU	-	.05 Mw		
12	Cold Springs Windfarm, LLC	LU	-	N/A	N/A	N/A
13	Consolidated Hydro Inc. / Enel		-			
14	Barber Dam	LU	-	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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	Dietrich Drop	LU	-	N/A	N/A	N/A
2	GeoBon #2	LU	-	N/A	N/A	N/A
3	Lowline #2	LU	-	N/A	N/A	N/A
4	Rock Creek #2	LU	-	N/A	N/A	N/A
5	Contractors Power Group Inc./Mile 28	LU	-	N/A	N/A	N/A
6	Crystal Springs Hydro	LU	-	N/A	N/A	N/A
7	Curry Cattle Company	LU	-	.084Mw		
8	David McCollum/Canyon Springs	LU	-	N/A	N/A	N/A
9	David R Snedigar	LU	-	N/A	N/A	N/A
10	Desert Meadow Wind Farm	LU	-	N/A	N/A	N/A
11	Eightmile Hydro Corp	LU	-	N/A	N/A	N/A
12	Faulkner Brothers Hydro Inc.	LU	-	N/A	N/A	N/A
13	Fisheries Development	OS	-	N/A	N/A	N/A
14	Fossil Gulch Wind	LU	-	N/A	N/A	N/A
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
14,262				802,944		802,944	1
3,031				228,100		228,100	2
10,091				537,227		537,227	3
6,250				328,832		328,832	4
4,766				337,984		337,984	5
9,621				659,848		659,848	6
744			26,796	30,741		57,537	7
482				8,074		8,074	8
1,386				97,333		97,333	9
51,329				3,531,906		3,531,906	10
1,378				75,765		75,765	11
3,540				274,398		274,398	12
1,205				19,937		19,937	13
21,790				1,245,178		1,245,178	14
3,788,934	276,510	162,239	2,815,124	204,436,381	10,345,099	217,596,604	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	G2 Energy Hidden Hollow	LU	-	N/A	N/A	N/A
2	Golden Valley Wind Park	LU	-	N/A	N/A	N/A
3	Hammett Hill Windfarm, LLC	LU	-	N/A	N/A	N/A
4	Hazelton B Power Company	LU	-	N/A	N/A	N/A
5	Head of U Canal	LU		N/A	N/A	N/A
6	High Mesa Energy	LU	-	N/A	N/A	N/A
7	H.K. Hydro Mud Creek S & S	LU	-	N/A	N/A	N/A
8	Horseshoe Bend Hydro	LU	-	N/A	N/A	N/A
9	Horseshoe Bend Wind/United Materials	LU	-	N/A	N/A	N/A
10	Hot Springs Wind Farm	LU	--	N/A	N/A	N/A
11	Idaho Winds / Sawtooth Wind Project	LU	-	N/A	N/A	N/A
12	J R Simplot Co.	LU	-	N/A	N/A	N/A
13	J.M. Miller/Sahko Hydro	LU	-	N/A	N/A	N/A
14	James B. Howell / CHI Elk Creek	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	04/15/2016	End of 2015/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
21,162				1,347,228		1,347,228	1
28,758				1,625,860		1,625,860	2
50,491				3,479,377		3,479,377	3
23,244				1,651,824		1,651,824	4
3,449				273,969		273,969	5
80,916				3,911,669		3,911,669	6
1,605				137,200		137,200	7
42,403				3,015,688		3,015,688	8
15,404				881,159		881,159	9
33,111				2,041,072		2,041,072	10
49,976				3,952,392		3,952,392	11
80,768				4,288,263		4,288,263	12
1,244				93,768		93,768	13
4,181				265,983		265,983	14
3,788,934	276,510	162,239	2,815,124	204,436,381	10,345,099	217,596,604	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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.

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

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

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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	John R LeMoyne	LU	--	N/A	N/A	N/A
2	Kasel & Witherspoon	LU	-	N/A	N/A	N/A
3	Kootenai Electric Cooperative / Fighti	LU	-	N/A	N/A	N/A
4	Koyle Hydro Inc.	LU	-	N/A	N/A	N/A
5	Lateral 10 Ventures	LU	-	N/A	N/A	N/A
6	Lemhi Hydro Power Co./Schaffner	LU	-	N/A	N/A	N/A
7	Lime Wind	LU	-	N/A	N/A	N/A
8	Little Mac Power Co./Cedar Draw	LU	-	N/A	N/A	N/A
9	Little Wood River Irrigation District	LU	-	N/A	N/A	N/A
10	Magic Reservoir Hydro	LU	-	N/A	N/A	N/A
11	Mainline Windfarm	LU	-	N/A	N/A	N/A
12	Marco Rancher's Irrigation Inc.	LU	-	N/A	N/A	N/A
13	Marysville Hydro Partners/Falls River	LU	-	N/A	N/A	N/A
14	Milner Dam Wind Park	LU	-	N/A	N/A	N/A
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		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)	
644				35,836		35,836	1
3,429				307,307		307,307	2
11,750				960,262		960,262	3
2,494				235,927		235,927	4
5,927				383,764		383,764	5
1,188				88,578		88,578	6
6,089				448,194		448,194	7
5,460				358,462		358,462	8
2,298				166,850		166,850	9
5,570				279,222		279,222	10
48,257				3,328,970		3,328,970	11
3,021				211,453		211,453	12
40,347				2,564,160		2,564,160	13
47,105				2,640,493		2,640,493	14
3,788,934	276,510	162,239	2,815,124	204,436,381	10,345,099	217,596,604	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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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	Mud Creek White Hydro, Inc	LU	-	N/A	N/A	N/A
2	New Energy One / Rock Creek Dairy	LU	-	N/A	N/A	N/A
3	Oregon Trail Wind Park	LU	-	N/A	N/A	N/A
4	Owyhee Irrigation District					
5	Mitchell Butte	LU	-	N/A	N/A	N/A
6	Owyhee Dam	LU		N/A	N/A	N/A
7	Tunnel #1	LU	-	N/A	N/A	N/A
8	Paynes Ferry Wind Park	LU	-	N/A	N/A	N/A
9	Pigeon Cove Power	LU	-	1.389Mw	[illegible]	[illegible]
10	Pilgrim Stage Station Wind Park	LU	-	N/A	N/A	N/A
11	Pristine Springs Inc #1	LU	-	N/A	N/A	N/A
12	Pristine Springs Inc. #3	LU	-	N/A	N/A	N/A
13	Reynolds Irrigation District	LU	-	N/A	N/A	N/A
14	Richard Kaster					
	Total					

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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)	
495				34,652		34,652	1
9,546				410,768		410,768	2
30,428				1,701,015		1,701,015	3
							4
1,076				33,412		33,412	5
8,507				215,727		215,727	6
							7
51,718				4,335,833		4,335,833	8
8,982			486,150	322,895		809,045	9
28,014				1,577,456		1,577,456	10
766				46,694		46,694	11
1,289				75,188		75,188	12
1,394				104,822		104,822	13
							14
3,788,934	276,510	162,239	2,815,124	204,436,381	10,345,099	217,596,604	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Box Canyon	LU	-	N/A	N/A	N/A
2	Briggs Creek	LU	-	N/A	N/A	N/A
3	Riverside Hydro/Mora Drop	LU	-	N/A	N/A	N/A
4	Riverside Investments					
5	Arena Drop	LU	-	N/A	N/A	N/A
6	Fargo Drop	LU	-	N/A	N/A	N/A
7	Rock Creek #1 Joint Venture	LU	-	1.732Mw		
8	Rockland Wind Project	LU	-	N/A	N/A	N/A
9	Rupert Cogeneration Partners/Magic Val	LU	-	N/A	N/A	N/A
10	Ryegrass Windfarm	LU	-	N/A	N/A	N/A
11	Salmon Falls Wind Park	LU	-	N/A	N/A	N/A
12	SE Hazelton A LP	LU	-	N/A	N/A	N/A
13	Shorock Hydro Inc.					
14	Shoshone CSPP	LU	-	N/A	N/A	N/A
	Total					

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
1,983				131,593		131,593	1
3,589				244,916		244,916	2
4,652				247,321		247,321	3
							4
1,501				113,516		113,516	5
3,498				194,410		194,410	6
10,617			552,508	438,780		991,288	7
218,662				13,836,699		13,836,699	8
76,677				5,138,703		5,138,703	9
46,727				3,212,867		3,212,867	10
53,270				2,990,578		2,990,578	11
23,982				1,653,087		1,653,087	12
							13
1,258				116,018		116,018	14
3,788,934	276,510	162,239	2,815,124	204,436,381	10,345,099	217,596,604	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Shoshone #2	LU	-	N/A	N/A	N/A
2	Snake River Pottery	LU	-	N/A	N/A	N/A
3	South Forks Joint Venture/Lowline Cana	LU	-	N/A	N/A	N/A
4	Tamarack Energy Partnership	LU	-	4.942Mw		
5	Tasco - Nampa	OS	-	N/A	N/A	N/A
6	Tasco - Twin Falls	OS	-	N/A	N/A	N/A
7	Ted S. Sorenson/Tiber Dam	LU	-	N/A	N/A	N/A
8	Thousand Springs Wind Park	LU	-	N/A	N/A	N/A
9	Tuana Gulch Wind Park	LU	-	N/A	N/A	N/A
10	Tuana Springs Expansion	LU	-	N/A	N/A	N/A
11	Twin Falls Energy/Lowline Midway Hydro	LU	-	N/A	N/A	N/A
12	Two Ponds Windfarm	LU	-	N/A	N/A	N/A
13	White Water Ranch	LU	-	N/A	N/A	N/A
14	William Arkoosh/Littlewood	LU	-	N/A	N/A	N/A
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
2,308				163,659		163,659	1
349				23,856		23,856	2
27,677				2,002,990		2,002,990	3
29,409			1,576,498	1,389,851		2,966,349	4
483				10,412		10,412	5
8							6
29,844				1,674,260		1,674,260	7
26,491				1,485,785		1,485,785	8
23,774				1,330,238		1,330,238	9
62,944				4,183,746		4,183,746	10
8,456				515,850		515,850	11
51,309				3,507,588		3,507,588	12
587				40,536		40,536	13
3,071				233,393		233,393	14
3,788,934	276,510	162,239	2,815,124	204,436,381	10,345,099	217,596,604	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Littlewood River Ranch II	LU		N/A	N/A	N/A
2	Willis and Betty Deveny/Shingle Creek	LU	-	N/A	N/A	N/A
3	Wilson Power Company	LU	-	N/A	N/A	N/A
4	Yahoo Creek Wind Park	LU	-	N/A	N/A	N/A
5	Prior Period Overpayment Recovery		-			
6	Scheduling Deviation		-			
7	Other Purchased Power					
8	ADM Investor Services Inc	OS		N/A	N/A	N/A
9	Arizona Public Service Co.	SF	WSPP	N/A	N/A	N/A
10	Avista Corp.	OS	T-12	N/A	N/A	N/A
11	Avista Corp.	SF	WSPP	N/A	N/A	N/A
12	Avista Corp.	OS	WSPP	N/A	N/A	N/A
13	Basin Electric Power Cooperative	SF	WSPP	N/A	N/A	N/A
14	Black Hills Power Inc.	SF	WSPP	N/A	N/A	N/A
	Total					

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

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

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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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)	
74				1,167		1,167	1
805				62,025		62,025	2
27,057				1,920,418		1,920,418	3
52,415				4,382,894		4,382,894	4
				-8,976		-8,976	5
2,190							6
							7
					-1,064,614	-1,064,614	8
34,096				1,047,016		1,047,016	9
21					537	537	10
75,515				1,952,680		1,952,680	11
					215,447	215,447	12
149				11,513		11,513	13
20				1,100		1,100	14
3,788,934	276,510	162,239	2,815,124	204,436,381	10,345,099	217,596,604	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

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

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
					297,481	297,481	1
135					3,512	3,512	2
103,286				2,926,124		2,926,124	3
12,898				485,020		485,020	4
18,450				441,070		441,070	5
					540,762	540,762	6
5,200				137,652		137,652	7
5					127	127	8
					151,944	151,944	9
76				2,006		2,006	10
833				9,100		9,100	11
60,385				2,250,545		2,250,545	12
10,495					697,010	697,010	13
650				11,936		11,936	14
3,788,934	276,510	162,239	2,815,124	204,436,381	10,345,099	217,596,604	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	Eugene Water & Electric Board	SF	WSPP	N/A	N/A	N/A
2	Exelon Generation Company, LLC	SF	WSPP	N/A	N/A	N/A
3	Grant CO Public Utility District #2 --	OS	WSPP	N/A	N/A	N/A
4	Grant CO Public Utility District #2 --	SF	WSPP	N/A	N/A	N/A
5	IBERDROLA RENEWABLES, Inc.	SF	WSPP	N/A	N/A	N/A
6	J. Aron & Company	SF	WSPP	N/A	N/A	N/A
7	Jefferies Bache	OS	-	N/A	N/A	N/A
8	Macquarie Energy LLC	OS	ISDA	N/A	N/A	N/A
9	Morgan Stanley Capital Group Inc.	SF	ISDA	N/A	N/A	N/A
10	Nevada Power Company, DBA NV Energy	SF	WSPP	N/A	N/A	N/A
11	Nevada Power Company, DBA NV Energy	OS	WSPP	N/A	N/A	N/A
12	Nobles Americas Energy Solutions LLC	SF	WSPP	N/A	N/A	N/A
13	NorthWestern Energy	OS	T-7	N/A	N/A	N/A
14	NorthWestern Energy	SF	WSPP	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
2,075				49,842		49,842	1
15,625				392,480		392,480	2
10					273	273	3
20,475				617,147		617,147	4
64,883				1,581,907		1,581,907	5
30,800				1,101,100		1,101,100	6
					-14,108	-14,108	7
					-286,198	-286,198	8
113,679				3,197,264		3,197,264	9
21,949				898,271		898,271	10
					6,703	6,703	11
6,400				218,208		218,208	12
21					532	532	13
5,427				102,523		102,523	14
3,788,934	276,510	162,239	2,815,124	204,436,381	10,345,099	217,596,604	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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	PacifiCorp Inc.	OS	T-13	N/A	N/A	N/A
2	PacifiCorp Inc.	SF	WSPP	N/A	N/A	N/A
3	PacifiCorp Inc.	OS	WSPP	N/A	N/A	N/A
4	Portland General Electric Company	OS	T-14	N/A	N/A	N/A
5	Portland General Electric Company	SF	WSPP	N/A	N/A	N/A
6	Powerex Corp.	SF	WSPP	N/A	N/A	N/A
7	Puget Sound Energy, Inc.	OS	T-9	N/A	N/A	N/A
8	Puget Sound Energy, Inc.	SF	WSPP	N/A	N/A	N/A
9	Rainbow Energy Marketing Corporation	SF	WSPP	N/A	N/A	N/A
10	Salt River Project	SF	WSPP	N/A	N/A	N/A
11	Seattle City Light	OS	WSPP	N/A	N/A	N/A
12	Seattle City Light	SF	WSPP	N/A	N/A	N/A
13	Shell Energy North America (US), L.P.	SF	WSPP	N/A	N/A	N/A
14	Sierra Pacific Power Co., dba NV Energ	OS	T-55	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	04/15/2016	End of 2015/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)	
99					2,575	2,575	1
690				16,900		16,900	2
					212,313	212,313	3
31					826	826	4
23,016				759,724		759,724	5
120,289				5,078,264		5,078,264	6
36					949	949	7
28,130				681,348		681,348	8
400				10,112		10,112	9
124,717				2,811,045		2,811,045	10
14					357	357	11
13,189				360,555		360,555	12
87,416				2,937,085		2,937,085	13
58					1,537	1,537	14
3,788,934	276,510	162,239	2,815,124	204,436,381	10,345,099	217,596,604	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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.

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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	Sierra Pacific Power Co., dba NV Energ	OS	WSPP	N/A	N/A	N/A
2	Snohomish County PUD	SF	WSPP	N/A	N/A	N/A
3	Tacoma Power	OS	WSPP	N/A	N/A	N/A
4	Tacoma Power	SF	WSPP	N/A	N/A	N/A
5	Talen Energy	SF	WSPP	N/A	N/A	N/A
6	Talen Energy	OS	WSPP	N/A	N/A	N/A
7	Tenaska Power Services Co.	SF	WSPP	N/A	N/A	N/A
8	The Energy Authority, Inc.	SF	WSPP	N/A	N/A	N/A
9	TransAlta Energy Marketing (U.S.) Inc.	SF	WSPP	N/A	N/A	N/A
10	Turlock Irrigation District	SF	WSPP	N/A	N/A	N/A
11	Raft River Energy I LLC	LU	-	N/A	N/A	N/A
12	Telocaset Wind Power Partners LLC	LU	APP-A	N/A	N/A	N/A
13	Neal Hot Springs Unit #1	LU	-	N/A	N/A	N/A
14	Oregon Solar Customers	OS	-	N/A	N/A	N/A
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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)	
					311	311	1
1,125				21,830		21,830	2
3					75	75	3
4,050				152,250		152,250	4
82,444				2,818,569		2,818,569	5
5,517					210,309	210,309	6
2,787				81,251		81,251	7
19,144				466,924		466,924	8
50,951				1,786,158		1,786,158	9
1,680				33,412		33,412	10
75,595				4,868,360		4,868,360	11
293,122				16,786,786		16,786,786	12
176,868				18,806,764		18,806,764	13
820					24,261	24,261	14
3,788,934	276,510	162,239	2,815,124	204,436,381	10,345,099	217,596,604	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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	Prior Year Adjustments	AD	-	N/A	N/A	N/A
2	Power Exchanges		-			
3	Avista Corp	EX		N/A	N/A	N/A
4	Bonneville Power Administration	EX	-	N/A	N/A	N/A
5	NorthWestern Energy	EX	-	N/A	N/A	N/A
6	PacifiCorp Inc.	EX	-	N/A	N/A	N/A
7	Sierra Pacific Power Co., dba NV Energ	EX	-	N/A	N/A	N/A
8	Clatskanie PUD	EX	153	N/A	N/A	N/A
9	Other Transactions					
10	Acctg Valuation of Clatskanie PUD	OS				
11	Demand Response Avoided Energy	OS	-	N/A	N/A	N/A
12	PacifiCorp Loss Repayment	OS	-	N/A	N/A	N/A
13	Black Thunder Test Burn	OS		N/A	N/A	N/A
14						
	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	04/15/2016	End of 2015/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)	
-6					237	237	1
							2
	359						3
	66,231						4
		448					5
	144,521	97,125					6
		1,691					7
	65,399	62,975					8
							9
					114,584	114,584	10
					6,701,263	6,701,263	11
64,775							12
					2,526,094	2,526,094	13
							14
3,788,934	276,510	162,239	2,815,124	204,436,381	10,345,099	217,596,604	

FOOTNOTE DATA

Schedule Page: 326 Line No.: 2 Column: e
Unavailable

Schedule Page: 326 Line No.: 2 Column: f
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Schedule Page: 326.1 Line No.: 11 Column: e
Unavailable

Schedule Page: 326.1 Line No.: 11 Column: f
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Schedule Page: 326.2 Line No.: 7 Column: e
Unavailable

Schedule Page: 326.2 Line No.: 7 Column: f
Unavailable

Schedule Page: 326.2 Line No.: 13 Column: b
Non-Firm Purchases

Schedule Page: 326.3 Line No.: 4 Column: a
Ida West, a subsidiary of Idaho Power Company, has partial ownership of these projects.

Schedule Page: 326.4 Line No.: 13 Column: a
Ida West, a subsidiary of Idaho Power Company, has partial ownership of these projects.

Schedule Page: 326.5 Line No.: 9 Column: e
Unavailable

Schedule Page: 326.5 Line No.: 9 Column: f
Unavailable

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

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

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

Schedule Page: 326.7 Line No.: 4 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: 326.7 Line No.: 4 Column: e
Unavailable

Schedule Page: 326.7 Line No.: 4 Column: f
Unavailable

Schedule Page: 326.7 Line No.: 5 Column: b
Non-Firm Purchases

Schedule Page: 326.7 Line No.: 6 Column: b
Non-Firm Purchases

Schedule Page: 326.8 Line No.: 3 Column: a
Ida West, a subsidiary of Idaho Power Company, has partial ownership of these projects.

Schedule Page: 326.8 Line No.: 6 Column: a
Difference between booked and scheduled energy.

Schedule Page: 326.8 Line No.: 8 Column: b
ADM Investor Services, Inc Futures Account Document, dated May 5, 2015

Schedule Page: 326.8 Line No.: 10 Column: b
Spinning or Operating Reserves

Schedule Page: 326.8 Line No.: 12 Column: b
Financial Transmission Losses

Schedule Page: 326.9 Line No.: 1 Column: b
Financial Transmission Losses

Schedule Page: 326.9 Line No.: 2 Column: b
Spinning or Operating Reserves

Schedule Page: 326.9 Line No.: 6 Column: b
ISDA Master Agreement With Cargill Power Markets, LLC, dated June 13, 2011

Schedule Page: 326.9 Line No.: 8 Column: b
Spinning or Operating Reserves

Schedule Page: 326.9 Line No.: 9 Column: b
ISDA Master Agreement with Citigroup Energy PLC dated March 7, 2011

Schedule Page: 326.9 Line No.: 13 Column: b
Unit Contingent Purchases

Schedule Page: 326.10 Line No.: 3 Column: b
Spinning or Operating Reserves

Schedule Page: 326.10 Line No.: 7 Column: b
Prudential Bache Commodities, LLC (Jefferies Bache) Futures Account Document, dated September 4, 2008 and contract ended on May 19, 2015.

Schedule Page: 326.10 Line No.: 8 Column: b
ISDA Master Agreement with Macquarie Energy, LLC dated April 12, 2011

Schedule Page: 326.10 Line No.: 11 Column: b
Financial Transmission Losses

Schedule Page: 326.10 Line No.: 13 Column: b
Spinning or Operating Reserves

Schedule Page: 326.11 Line No.: 1 Column: b
Spinning or Operating Reserves

Schedule Page: 326.11 Line No.: 3 Column: b
Financial Transmission Losses

Schedule Page: 326.11 Line No.: 4 Column: b
Spinning or Operating Reserves

Schedule Page: 326.11 Line No.: 7 Column: b
Spinning or Operating Reserves

Schedule Page: 326.11 Line No.: 11 Column: b
Spinning or Operating Reserves

Schedule Page: 326.11 Line No.: 14 Column: b
Spinning or Operating Reserves

Schedule Page: 326.12 Line No.: 1 Column: b
Financial Transmission Losses

Schedule Page: 326.12 Line No.: 3 Column: b
Spinning or Operating Reserves

Schedule Page: 326.12 Line No.: 6 Column: b
Unit Contingent Purchases

Schedule Page: 326.12 Line No.: 14 Column: b
Schedule 88 Oregon Solar

Schedule Page: 326.13 Line No.: 1 Column: b
Out of period adjustments

Schedule Page: 326.13 Line No.: 3 Column: b
Financial Transmission Losses

Schedule Page: 326.13 Line No.: 4 Column: b
Financial Transmission Losses

Schedule Page: 326.13 Line No.: 5 Column: b
Financial Transmission Losses

Schedule Page: 326.13 Line No.: 6 Column: b
Financial Transmission Losses

Schedule Page: 326.13 Line No.: 7 Column: b
Financial Transmission Losses

Schedule Page: 326.13 Line No.: 8 Column: b
Energy exchange between Clatskanie PUD and Idaho Power Company at Arrowrock Dam.

Schedule Page: 326.13 Line No.: 10 Column: b
Energy exchange between Clatskanie PUD and Idaho Power Company at Arrowrock Dam.

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FOOTNOTE DATA

Schedule Page: 326.13 Line No.: 11 Column: b

Incentive program for customers to reduce demand during peak hours

Schedule Page: 326.13 Line No.: 12 Column: b

Repayment of transmisssion losses

Schedule Page: 326.13 Line No.: 13 Column: b

Coal supply test burn at Jim Bridger Plant

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Bonneville Power Administration - OTEC	Bonneville Power Administration	Oregon Trails Electric Co-op	FNO
2	Bonneville Power Administration - 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	PacifiCorp - Imnaha	PacifiCorp West	PacifiCorp West	FNO
8	PacifiCorp - Imnaha	PacifiCorp West	PacifiCorp West	AD
9	Milner Irrigation District	United States Bureau of Reclamati	Milner Irrigation District	OLF
10	United States Bureau of Indian Affairs	Bonneville Power Administration	United States Bureau of Indian Af	OS
11	Shell Energy North America (US), L.P.	Seattle City Light	Bonneville Power Administration	OS
12	United Materials of Great Falls	NorthWestern/PacifiCorp East	Idaho Power Company	OS
13	United Materials of Great Falls	PacifiCorp East	Idaho Power Company	OS
14	United Materials of Great Falls	PacifiCorp East	Sierra Pacific Power	OS
15	United Materials of Great Falls			AD
16				
17	PacifiCorp Inc.	PacifiCorp East	PacifiCorp East	LFP
18	PacifiCorp Inc.	PacifiCorp East	Bonneville Power Administration	LFP
19	PacifiCorp Inc.	PacifiCorp East	PacifiCorp West	LFP
20	PacifiCorp Inc.	Idaho Power Company	Idaho Power Company	LFP
21	PacifiCorp Inc.	PacifiCorp East	PacifiCorp West	LFP
22	Shell Energy North America (US), L.P.	Idaho Power Company	Bonneville Power Administration	LFP
23				
24	Black Hills Power			NF
25	Bonneville Power Adminstration	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
26	Bonneville Power Adminstration	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
27	Bonneville Power Adminstration	Bonneville Power Administration	Bonneville Power Administration	NF
28	Bonneville Power Adminstration	Bonneville Power Administration	Sierra Pacific Power	NF
29	Bonneville Power Adminstration	Avista	Bonneville Power Administration	NF
30	Bonneville Power Adminstration	Avista	Sierra Pacific Power	NF
31	Bonneville Power Administration			AD
32	Cargill-Alliant			AD
33	Iberdrola Renewables LLC	NorthWestern/PacifiCorp East	PacifiCorp East	NF
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 MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
9				336,735	336,735	1
9						2
9				297,100	297,100	3
9						4
9				1,260,469	1,260,469	5
9						6
9				2,067	2,067	7
9						8
Legacy	Minidoka, Idaho	Various in Idaho		9,393	9,393	9
Legacy	LaGrande, Oregon	Various in Idaho		16,261	16,261	10
4				277,687	277,687	11
5/6				6	6	12
5/6				7,539	7,539	13
5/6				7,859	7,859	14
5/6						15
						16
7/8	BORA	KPRT		663,949	663,949	17
7/8	BORA	LAGRANDE		69,227	69,227	18
7/8	BORA	HURR		287,668	287,668	19
7/8	JBWT	HMWY		470,041	470,041	20
7/8	KPRT	HURR		121,062	121,062	21
7/8	LYPK	LAGRANDE		21,675	21,675	22
						23
7/8						24
7/8	BPAT.NWMT	LAGRANDE		1,369	1,369	25
7/8	BPAT.NWMT	M345		266	266	26
7/8	LAGRANDE	LAGRANDE		776	776	27
7/8	LAGRANDE	M345		10,813	10,813	28
7/8	LOLO	LAGRANDE		3,193	3,193	29
7/8	LOLO	M345		1,956	1,956	30
7/8						31
7/8						32
7/8	BPAT.NWMT	BRDY		40	40	33
						34
			0	**5,920,350**	**5,920,350**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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	Iberdrola Renewables LLC	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
2	Iberdrola Renewables LLC	PacifiCorp East	Sierra Pacific Power	NF
3	Iberdrola Renewables LLC	PacifiCorp East	Bonneville Power Administration	NF
4	Iberdrola Renewables LLC	Idaho Power Company	PacifiCorp East	NF
5	Iberdrola Renewables LLC	Idaho Power Company	Sierra Pacific Power	NF
6	Iberdrola Renewables LLC	PacifiCorp East	Sierra Pacific Power	NF
7	Iberdrola Renewables LLC	Bonneville Power Administration	PacifiCorp East	NF
8	Iberdrola Renewables LLC	Bonneville Power Administration	Sierra Pacific Power	NF
9	Iberdrola Renewables LLC	Avista	PacifiCorp East	NF
10	Iberdrola Renewables LLC	Avista	Sierra Pacific Power	NF
11	Iberdrola Renewables LLC	Sierra Pacific Power	Bonneville Power Administration	NF
12	Iberdrola Renewables LLC	PacifiCorp West	PacifiCorp East	NF
13	Iberdrola Renewables LLC			AD
14	MacQuarie Cook	Bonneville Power Administration	Sierra Pacific Power	NF
15	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
16	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Idaho Power Company	NF
17	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
18	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
19	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp West	SFP
20	Morgan Stanley Capital Group Inc.	PacifiCorp East	Bonneville Power Administration	NF
21	Morgan Stanley Capital Group Inc.	PacifiCorp East	Sierra Pacific Power	NF
22	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
23	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
24	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
25	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
26	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp West	SFP
27	Morgan Stanley Capital Group Inc.	PacifiCorp East	NorthWestern/PacifiCorp East	NF
28	Morgan Stanley Capital Group Inc.	PacifiCorp East	PacifiCorp East	NF
29	Morgan Stanley Capital Group Inc.	PacifiCorp East	Idaho Power Company	NF
30	Morgan Stanley Capital Group Inc.	PacifiCorp East	PacifiCorp West	NF
31	Morgan Stanley Capital Group Inc.	PacifiCorp East	Bonneville Power Administration	NF
32	Morgan Stanley Capital Group Inc.	PacifiCorp East	Avista	NF
33	Morgan Stanley Capital Group Inc.	PacifiCorp East	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	04/15/2016	End of 2015/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.
7/8	BPAT.NWMT	M345		115	115	1
7/8	BRDY	M345		40	40	2
7/8	GSHN	LAGRANDE		62	62	3
7/8	HMWY	BORA		3,286	3,286	4
7/8	HMWY	M345		635	635	5
7/8	JBSN	M345		140	140	6
7/8	LAGRANDE	BORA		1,669	1,669	7
7/8	LAGRANDE	M345		9,565	9,565	8
7/8	LOLO	BORA		40	40	9
7/8	LOLO	M345		1,762	1,762	10
7/8	M345	LAGRANDE		1,214	1,214	11
7/8	SMLK	BORA		250	250	12
7/8						13
7/8	LAGRANDE	M345		379	379	14
7/8	AVAT.NWMT	BORA		309	309	15
7/8	AVAT.NWMT	HMWY		25	25	16
7/8	AVAT.NWMT	LAGRANDE		856	856	17
7/8	AVAT.NWMT	M345		47,673	47,673	18
7/8	AVAT.NWMT	M345		29,450	29,450	19
7/8	BORA	LAGRANDE		410	410	20
7/8	BORA	M345		3,187	3,187	21
7/8	BPAT.NWMT	BORA		1,350	1,350	22
7/8	BPAT.NWMT	BRDY		612	612	23
7/8	BPAT.NWMT	LAGRANDE		6,720	6,720	24
7/8	BPAT.NWMT	M345		6,527	6,527	25
7/8	BPAT.NWMT	M345		5,382	5,382	26
7/8	BRDY	AVAT.NWMT		19	19	27
7/8	BRDY	BORA		540	540	28
7/8	BRDY	HMWY		607	607	29
7/8	BRDY	HURR		10	10	30
7/8	BRDY	LAGRANDE		10,379	10,379	31
7/8	BRDY	LOLO		186	186	32
7/8	BRDY	M345		37,611	37,611	33
						34
			0	5,920,350	5,920,350	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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.	PacifiCorp East	PacifiCorp West	SFP
2	Morgan Stanley Capital Group Inc.	PacifiCorp West	PacifiCorp East	NF
3	Morgan Stanley Capital Group Inc.	PacifiCorp West	PacifiCorp East	NF
4	Morgan Stanley Capital Group Inc.	PacifiCorp West	Sierra Pacific Power	NF
5	Morgan Stanley Capital Group Inc.	Idaho Power Company	PacifiCorp East	NF
6	Morgan Stanley Capital Group Inc.	Idaho Power Company	PacifiCorp East	NF
7	Morgan Stanley Capital Group Inc.	Idaho Power Company	Sierra Pacific Power	NF
8	Morgan Stanley Capital Group Inc.	PacifiCorp East	Sierra Pacific Power	NF
9	Morgan Stanley Capital Group Inc.	PacifiCorp West	PacifiCorp West	SFP
10	Morgan Stanley Capital Group Inc.	Idaho Power Company	Sierra Pacific Power	NF
11	Morgan Stanley Capital Group Inc.	PacifiCorp East	PacifiCorp East	NF
12	Morgan Stanley Capital Group Inc.	PacifiCorp East	Bonneville Power Administration	NF
13	Morgan Stanley Capital Group Inc.	PacifiCorp East	Sierra Pacific Power	NF
14	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp West	SFP
15	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	PacifiCorp East	NF
16	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	PacifiCorp East	SFP
17	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	PacifiCorp East	NF
18	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	Sierra Pacific Power	NF
19	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	PacifiCorp West	SFP
20	Morgan Stanley Capital Group Inc.	Avista	PacifiCorp East	NF
21	Morgan Stanley Capital Group Inc.	Avista	PacifiCorp East	SFP
22	Morgan Stanley Capital Group Inc.	Avista	PacifiCorp East	NF
23	Morgan Stanley Capital Group Inc.	Avista	PacifiCorp East	NF
24	Morgan Stanley Capital Group Inc.	Avista	Bonneville Power Administration	NF
25	Morgan Stanley Capital Group Inc.	Avista	Sierra Pacific Power	NF
26	Morgan Stanley Capital Group Inc.	Avista	PacifiCorp West	SFP
27	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
28	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
29	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	PacifiCorp East	NF
30	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	PacifiCorp East	NF
31	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	Bonneville Power Administration	NF
32	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	Avista	NF
33	Morgan Stanley Capital Group Inc.			AD
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	04/15/2016	End of 2015/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.
7/8	BRDY	M345		3,885	3,885	1
7/8	ENPR	BORA		1,379	1,379	2
7/8	ENPR	BRDY		146	146	3
7/8	ENPR	M345		8,288	8,288	4
7/8	HMWY	BORA		804	804	5
7/8	HMWY	BRDY		134	134	6
7/8	HMWY	M345		5,033	5,033	7
7/8	JBSN	M345		1,366	1,366	8
7/8	JBSN	M345		4,081	4,081	9
7/8	JBWT	M345		287	287	10
7/8	JEFF	BORA		316	316	11
7/8	JEFF	LAGRANDE		11,344	11,344	12
7/8	JEFF	M345		158,131	158,131	13
7/8	JEFF	M345		1,450	1,450	14
7/8	LAGRANDE	BORA		3,142	3,142	15
7/8	LAGRANDE	BORA		566	566	16
7/8	LAGRANDE	BRDY		1,844	1,844	17
7/8	LAGRANDE	M345		27,130	27,130	18
7/8	LAGRANDE	M345		140	140	19
7/8	LOLO	BORA		6,356	6,356	20
7/8	LOLO	BORA		368	368	21
7/8	LOLO	BRDY		507	507	22
7/8	LOLO	JEFF		32	32	23
7/8	LOLO	LAGRANDE		117	117	24
7/8	LOLO	M345		135,160	135,160	25
7/8	LOLO	M345		191,191	191,191	26
7/8	M345	AVAT.NWMT		451	451	27
7/8	M345	BPAT.NWMT		416	416	28
7/8	M345	BRDY		80	80	29
7/8	M345	JEFF		82	82	30
7/8	M345	LAGRANDE		415	415	31
7/8	M345	LOLO		95	95	32
7/8						33
						34
			0	**5,920,350**	**5,920,350**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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	PacifiCorp East	Sierra Pacific Power	NF
2	Nevada Power Company	PacifiCorp East	Sierra Pacific Power	NF
3	Nevada Power Company	Idaho Power Company	Sierra Pacific Power	NF
4	Nevada Power Company	PacifiCorp East	Sierra Pacific Power	NF
5	Nevada Power Company	Bonneville Power Administration	Sierra Pacific Power	NF
6	Nevada Power Company	Avista	Sierra Pacific Power	NF
7	Nevada Power Company	Avista	PacifiCorp West	SFP
8	Nevada Power Company			AD
9	PacifiCorp Inc.	PacifiCorp East	PacifiCorp West	NF
10	PacifiCorp Inc.	PacifiCorp East	Idaho Power Company	NF
11	PacifiCorp Inc.	PacifiCorp East	PacifiCorp West	NF
12	PacifiCorp Inc.	PacifiCorp East	Sierra Pacific Power	NF
13	PacifiCorp Inc.	PacifiCorp East	PacifiCorp East	NF
14	PacifiCorp Inc.	PacifiCorp East	PacifiCorp East	SFP
15	PacifiCorp Inc.	PacifiCorp East	PacifiCorp West	NF
16	PacifiCorp Inc.	PacifiCorp East	PacifiCorp East	NF
17	PacifiCorp Inc.	PacifiCorp East	Bonneville Power Administration	NF
18	PacifiCorp Inc.	PacifiCorp West	PacifiCorp East	NF
19	PacifiCorp Inc.	PacifiCorp West	PacifiCorp East	SFP
20	PacifiCorp Inc.	PacifiCorp West	PacifiCorp East	NF
21	PacifiCorp Inc.	PacifiCorp West	PacifiCorp East	NF
22	PacifiCorp Inc.	PacifiCorp West	PacifiCorp East	SFP
23	PacifiCorp Inc.	Idaho Power Company	PacifiCorp East	NF
24	PacifiCorp Inc.	Idaho Power Company	PacifiCorp East	NF
25	PacifiCorp Inc.	Idaho Power Company	Idaho Power Company	NF
26	PacifiCorp Inc.	Idaho Power Company	PacifiCorp East	NF
27	PacifiCorp Inc.	Idaho Power Company	Bonneville Power Administration	NF
28	PacifiCorp Inc.	Idaho Power Company	Avista	NF
29	PacifiCorp Inc.	Avista	PacifiCorp East	NF
30	PacifiCorp Inc.	Avista	PacifiCorp West	NF
31	PacifiCorp Inc.			AD
32	Portland General Electric Company	PacifiCorp East	NorthWestern/PacifiCorp East	NF
33	Portland General Electric Company	PacifiCorp East	Bonneville Power Administration	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	04/15/2016	End of 2015/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.
7/8	BORA	M345		2,020	2,020	1
7/8	BRDY	M345		1,011	1,011	2
7/8	HMWY	M345		750	750	3
7/8	JEFF	M345		1,409	1,409	4
7/8	LAGRANDE	M345		701	701	5
7/8	LOLO	M345		4,065	4,065	6
7/8	LOLO	M345		2,400	2,400	7
7/8						8
7/8	BORA	ENPR		4,279	4,279	9
7/8	BORA	HMWY		745	745	10
7/8	BORA	HURR		837	837	11
7/8	BORA	M345		48	48	12
7/8	BRDY	BRDY		1,061	1,061	13
7/8	BRDY	BRDY		2,244	2,244	14
7/8	BRDY	ENPR		7,978	7,978	15
7/8	BRDY	KPRT		553	553	16
7/8	BRDY	LAGRANDE		16,396	16,396	17
7/8	ENPR	BORA		136,570	136,570	18
7/8	ENPR	BORA		2,176	2,176	19
7/8	ENPR	BRDY		884	884	20
7/8	HURR	BORA		219	219	21
7/8	HURR	BORA		5,604	5,604	22
7/8	JBWT	BORA		1,126	1,126	23
7/8	JBWT	GSHN		51	51	24
7/8	JBWT	HMWY		4,000	4,000	25
7/8	JBWT	KPRT		4,975	4,975	26
7/8	JBWT	LAGRANDE		154,480	154,480	27
7/8	JBWT	LOLO		1,637	1,637	28
7/8	LOLO	BORA		2,239	2,239	29
7/8	LOLO	ENPR		8,820	8,820	30
7/8						31
7/8	BORA	BPAT.NWMT		250	250	32
7/8	BORA	LAGRANDE		1,670	1,670	33
						34
			0	**5,920,350**	**5,920,350**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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	Portland General Electric Company	PacifiCorp East	Sierra Pacific Power	NF
2	Portland General Electric Company	NorthWestern/PacifiCorp East	PacifiCorp East	NF
3	Portland General Electric Company	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
4	Portland General Electric Company	PacifiCorp East	Bonneville Power Administration	NF
5	Portland General Electric Company	Idaho Power Company	PacifiCorp East	NF
6	Portland General Electric Company	Idaho Power Company	Sierra Pacific Power	NF
7	Portland General Electric Company	Idaho Power Company	PacifiCorp East	NF
8	Portland General Electric Company	Idaho Power Company	Bonneville Power Administration	NF
9	Portland General Electric Company	PacifiCorp East	Bonneville Power Administration	NF
10	Portland General Electric Company	Bonneville Power Administration	PacifiCorp East	NF
11	Portland General Electric Company	Bonneville Power Administration	Sierra Pacific Power	NF
12	Portland General Electric Company	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
13	Portland General Electric Company	Sierra Pacific Power	Bonneville Power Administration	NF
14	Portland General Electric Company			AD
15	Powerex Corporation	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
16	Powerex Corporation	PacifiCorp East	NorthWestern/PacifiCorp East	SFP
17	Powerex Corporation	PacifiCorp East	PacifiCorp West	NF
18	Powerex Corporation	PacifiCorp East	Idaho Power Company	NF
19	Powerex Corporation	PacifiCorp East	PacifiCorp East	NF
20	Powerex Corporation	PacifiCorp East	Bonneville Power Administration	NF
21	Powerex Corporation	PacifiCorp East	Sierra Pacific Power	NF
22	Powerex Corporation	NorthWestern/PacifiCorp East	PacifiCorp East	NF
23	Powerex Corporation	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
24	Powerex Corporation	NorthWestern/PacifiCorp East	PacifiCorp East	NF
25	Powerex Corporation	NorthWestern/PacifiCorp East	Idaho Power Company	NF
26	Powerex Corporation	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
27	Powerex Corporation	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
28	Powerex Corporation	NorthWestern/PacifiCorp East	PacifiCorp West	SFP
29	Powerex Corporation	PacifiCorp East	NorthWestern/PacifiCorp East	NF
30	Powerex Corporation	PacifiCorp East	Idaho Power Company	NF
31	Powerex Corporation	PacifiCorp East	Bonneville Power Administration	NF
32	Powerex Corporation	PacifiCorp East	Sierra Pacific Power	NF
33	Powerex Corporation	PacifiCorp West	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) 04/15/2016	Year/Period of Report End of 2015/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.
7/8	BORA	M345		2	2	1
7/8	BPAT.NWMT	BORA		200	200	2
7/8	BPAT.NWMT	M345		100	100	3
7/8	BRDY	LAGRANDE		10,396	10,396	4
7/8	HMWY	BORA		1,535	1,535	5
7/8	HMWY	M345		3,900	3,900	6
7/8	JBWT	BORA		114	114	7
7/8	JBWT	LAGRANDE		75	75	8
7/8	JEFF	LAGRANDE		1,435	1,435	9
7/8	LAGRANDE	BORA		979	979	10
7/8	LAGRANDE	M345		813	813	11
7/8	M345	BPAT.NWMT		50	50	12
7/8	M345	LAGRANDE		324	324	13
7/8						14
7/8	AVAT.NWMT	M345		76	76	15
7/8	BORA	BPAT.NWMT		512	512	16
7/8	BORA	ENPR		80	80	17
7/8	BORA	HMWY		525	525	18
7/8	BORA	JEFF		30	30	19
7/8	BORA	LAGRANDE		211	211	20
7/8	BORA	M345		184	184	21
7/8	BPAT.NWMT	BORA		1,558	1,558	22
7/8	BPAT.NWMT	BORA		2,613	2,613	23
7/8	BPAT.NWMT	BRDY		588	588	24
7/8	BPAT.NWMT	IPCOLOSS		43	43	25
7/8	BPAT.NWMT	LAGRANDE		1,012	1,012	26
7/8	BPAT.NWMT	M345		7,276	7,276	27
7/8	BPAT.NWMT	M345		55,295	55,295	28
7/8	BRDY	BPAT.NWMT		213	213	29
7/8	BRDY	HMWY		41	41	30
7/8	BRDY	LAGRANDE		2,849	2,849	31
7/8	BRDY	M345		2,430	2,430	32
7/8	ENPR	BORA		47,641	47,641	33
						34
			0	**5,920,350**	**5,920,350**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Powerex Corporation	PacifiCorp West	PacifiCorp East	SFP
2	Powerex Corporation	PacifiCorp West	PacifiCorp East	NF
3	Powerex Corporation	PacifiCorp West	Sierra Pacific Power	NF
4	Powerex Corporation	PacifiCorp West	PacifiCorp West	SFP
5	Powerex Corporation	PacifiCorp East	Bonneville Power Administration	NF
6	Powerex Corporation	PacifiCorp East	Sierra Pacific Power	NF
7	Powerex Corporation	Idaho Power Company	PacifiCorp East	NF
8	Powerex Corporation	Idaho Power Company	PacifiCorp East	NF
9	Powerex Corporation	Idaho Power Company	Sierra Pacific Power	NF
10	Powerex Corporation	PacifiCorp East	Sierra Pacific Power	NF
11	Powerex Corporation	Idaho Power Company	Idaho Power Company	NF
12	Powerex Corporation	PacifiCorp East	PacifiCorp East	NF
13	Powerex Corporation	PacifiCorp East	PacifiCorp East	NF
14	Powerex Corporation	Bonneville Power Administration	PacifiCorp East	NF
15	Powerex Corporation	Bonneville Power Administration	PacifiCorp East	NF
16	Powerex Corporation	Bonneville Power Administration	Idaho Power Company	NF
17	Powerex Corporation	Bonneville Power Administration	Sierra Pacific Power	NF
18	Powerex Corporation	Bonneville Power Administration	PacifiCorp West	SFP
19	Powerex Corporation	Avista	PacifiCorp East	NF
20	Powerex Corporation	Avista	PacifiCorp East	NF
21	Powerex Corporation	Avista	Sierra Pacific Power	NF
22	Powerex Corporation	Avista	PacifiCorp West	SFP
23	Powerex Corporation	Sierra Pacific Power	PacifiCorp East	NF
24	Powerex Corporation	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
25	Powerex Corporation	Sierra Pacific Power	PacifiCorp East	NF
26	Powerex Corporation	Sierra Pacific Power	Bonneville Power Administration	NF
27	Powerex Corporation	PacifiCorp West	PacifiCorp East	NF
28	Powerex Corporation	PacifiCorp West	PacifiCorp East	NF
29	Powerex Corporation	PacifiCorp West	Sierra Pacific Power	NF
30	Powerex Corporation			AD
31	Puget Sound Energy, Inc.	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
32	Puget Sound Energy, Inc.	Sierra Pacific Power	Bonneville Power Administration	NF
33	Shell Energy North America (US), L.P.	PacifiCorp East	Sierra Pacific Power	SFP
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	04/15/2016	End of 2015/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.
7/8	ENPR	BORA		12,700	12,700	1
7/8	ENPR	BRDY		1,590	1,590	2
7/8	ENPR	M345		6,152	6,152	3
7/8	ENPR	M345		2,534	2,534	4
7/8	GSHN	LAGRANDE		905	905	5
7/8	GSHN	M345		60	60	6
7/8	HMWY	BORA		44,475	44,475	7
7/8	HMWY	BRDY		3,587	3,587	8
7/8	HMWY	M345		22,746	22,746	9
7/8	JBSN	M345		49	49	10
7/8	JBWT	HMWY		265	265	11
7/8	JEFF	BORA		25	25	12
7/8	JEFF	BRDY		59	59	13
7/8	LAGRANDE	BORA		15,644	15,644	14
7/8	LAGRANDE	BRDY		3,628	3,628	15
7/8	LAGRANDE	IPCOLOSS		27	27	16
7/8	LAGRANDE	M345		56,732	56,732	17
7/8	LAGRANDE	M345		266	266	18
7/8	LOLO	BORA		885	885	19
7/8	LOLO	BRDY		216	216	20
7/8	LOLO	M345		14,872	14,872	21
7/8	LOLO	M345		7,598	7,598	22
7/8	M345	BORA		125	125	23
7/8	M345	BPAT.NWMT		116	116	24
7/8	M345	JEFF		50	50	25
7/8	M345	LAGRANDE		2,764	2,764	26
7/8	SMLK	BORA		3,003	3,003	27
7/8	SMLK	BRDY		138	138	28
7/8	SMLK	M345		648	648	29
7/8						30
7/8	M345	BPAT.NWMT		1	1	31
7/8	M345	LAGRANDE		40	40	32
7/8	BORA	M345		440	440	33
						34
			0	**5,920,350**	**5,920,350**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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	Shell Energy North America (US), L.P.	PacifiCorp East	NorthWestern/PacifiCorp East	NF
2	Shell Energy North America (US), L.P.	PacifiCorp East	Bonneville Power Administration	NF
3	Shell Energy North America (US), L.P.	PacifiCorp East	Sierra Pacific Power	NF
4	Shell Energy North America (US), L.P.	PacifiCorp East	PacifiCorp West	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	NF
7	Shell Energy North America (US), L.P.	Idaho Power Company	Sierra Pacific Power	NF
8	Shell Energy North America (US), L.P.	Idaho Power Company	PacifiCorp West	SFP
9	Shell Energy North America (US), L.P.	Idaho Power Company	PacifiCorp East	NF
10	Shell Energy North America (US), L.P.	Idaho Power Company	Bonneville Power Administration	NF
11	Shell Energy North America (US), L.P.	Idaho Power Company	Sierra Pacific Power	NF
12	Shell Energy North America (US), L.P.	PacifiCorp East	Bonneville Power Administration	NF
13	Shell Energy North America (US), L.P.	PacifiCorp East	Sierra Pacific Power	NF
14	Shell Energy North America (US), L.P.	NorthWestern/PacifiCorp East	PacifiCorp West	SFP
15	Shell Energy North America (US), L.P.	Bonneville Power Administration	PacifiCorp East	NF
16	Shell Energy North America (US), L.P.	Bonneville Power Administration	PacifiCorp East	SFP
17	Shell Energy North America (US), L.P.	Bonneville Power Administration	Avista	NF
18	Shell Energy North America (US), L.P.	Bonneville Power Administration	Sierra Pacific Power	NF
19	Shell Energy North America (US), L.P.	Bonneville Power Administration	PacifiCorp West	SFP
20	Shell Energy North America (US), L.P.	Avista	Idaho Power Company	NF
21	Shell Energy North America (US), L.P.	Avista	Bonneville Power Administration	NF
22	Shell Energy North America (US), L.P.	Avista	Sierra Pacific Power	NF
23	Shell Energy North America (US), L.P.	Avista	PacifiCorp West	SFP
24	Shell Energy North America (US), L.P.	Idaho Power Company	PacifiCorp East	SFP
25	Shell Energy North America (US), L.P.	Idaho Power Company	PacifiCorp East	NF
26	Shell Energy North America (US), L.P.	Sierra Pacific Power	PacifiCorp East	SFP
27	Shell Energy North America (US), L.P.	Idaho Power Company	Idaho Power Company	NF
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	Sierra Pacific Power	NF
30	Shell Energy North America (US), L.P.	Sierra Pacific Power	PacifiCorp West	SFP
31	Shell Energy North America (US), L.P.	Sierra Pacific Power	PacifiCorp East	NF
32	Shell Energy North America (US), L.P.	Sierra Pacific Power	Idaho Power Company	NF
33	Shell Energy North America (US), L.P.	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) 04/15/2016	Year/Period of Report End of 2015/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)	
7/8	BRDY	BPAT.NWMT		50	50	1
7/8	BRDY	LAGRANDE		3,387	3,387	2
7/8	BRDY	M345		43,016	43,016	3
7/8	BRDY	M345		68,767	68,767	4
7/8	ENPR	LAGRANDE		36	36	5
7/8	ENPR	M345		1,218	1,218	6
7/8	HMWY	M345		5,144	5,144	7
7/8	HMWY	M345		2,417	2,417	8
7/8	IPCOGEN	BRDY		30	30	9
7/8	IPCOGEN	LAGRANDE		924	924	10
7/8	IPCOGEN	M345		5	5	11
7/8	JEFF	LAGRANDE		182	182	12
7/8	JEFF	M345		651	651	13
7/8	JEFF	M345		1,176	1,176	14
7/8	LAGRANDE	BRDY		1,040	1,040	15
7/8	LAGRANDE	BRDY		900	900	16
7/8	LAGRANDE	LOLO		56	56	17
7/8	LAGRANDE	M345		98,756	98,756	18
7/8	LAGRANDE	M345		1,216	1,216	19
7/8	LOLO	IPCO		56	56	20
7/8	LOLO	LAGRANDE		68	68	21
7/8	LOLO	M345		7,660	7,660	22
7/8	LOLO	M345		16,512	16,512	23
7/8	LYPK	BORA		230	230	24
7/8	LYPK	BRDY		19,241	19,241	25
7/8	LYPK	BRDY		5,464	5,464	26
7/8	LYPK	HMWY		71	71	27
7/8	LYPK	LAGRANDE		10,872	10,872	28
7/8	LYPK	M345		77,800	77,800	29
7/8	LYPK	M345		132,217	132,217	30
7/8	M345	BRDY		50	50	31
7/8	M345	HMWY		248	248	32
7/8	M345	LAGRANDE		4,397	4,397	33
						34
			0	**5,920,350**	**5,920,350**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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	Shell Energy North America (US), L.P.	Idaho Power Company	Bonneville Power Administration	NF
2	Shell Energy North America (US), L.P.	Idaho Power Company	Avista	NF
3	Shell Energy North America (US), L.P.	Idaho Power Company	Bonneville Power Administration	NF
4	Shell Energy North America (US), L.P.	PacifiCorp West	Sierra Pacific Power	NF
5	Shell Energy North America (US), L.P.	PacifiCorp West	PacifiCorp West	SFP
6	Shell Energy North America (US), L.P.			AD
7	Talen Energy	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
8	Talen Energy	PacifiCorp East	Idaho Power Company	NF
9	Talen Energy	PacifiCorp East	Idaho Power Company	NF
10	Talen Energy	PacifiCorp East	Bonneville Power Administration	NF
11	Talen Energy	Idaho Power Company	PacifiCorp East	NF
12	Talen Energy	Idaho Power Company	Sierra Pacific Power	NF
13	Talen Energy	PacifiCorp East	PacifiCorp East	NF
14	Talen Energy	PacifiCorp East	Bonneville Power Administration	NF
15	Talen Energy	Avista	PacifiCorp East	NF
16	Talen Energy	Sierra Pacific Power	PacifiCorp East	NF
17	Talen Energy			AD
18	Tenaska Power Services Co.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
19	Tenaska Power Services Co.	PacifiCorp East	Bonneville Power Administration	NF
20	Tenaska Power Services Co.	PacifiCorp East	Sierra Pacific Power	NF
21	Tenaska Power Services Co.	PacifiCorp East	Sierra Pacific Power	NF
22	The Energy Authority, Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
23	The Energy Authority, Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
24	The Energy Authority, Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
25	The Energy Authority, Inc.	NorthWestern/PacifiCorp East	PacifiCorp West	SFP
26	The Energy Authority, Inc.	PacifiCorp East	NorthWestern/PacifiCorp East	NF
27	The Energy Authority, Inc.	PacifiCorp East	Idaho Power Company	NF
28	The Energy Authority, Inc.	PacifiCorp East	Bonneville Power Administration	NF
29	The Energy Authority, Inc.	Idaho Power Company	PacifiCorp East	NF
30	The Energy Authority, Inc.	Idaho Power Company	PacifiCorp East	NF
31	The Energy Authority, Inc.	Idaho Power Company	Sierra Pacific Power	NF
32	The Energy Authority, Inc.	Bonneville Power Administration	PacifiCorp East	NF
33	The Energy Authority, Inc.	Bonneville Power Administration	PacifiCorp East	NF
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 MegaWatt Hours Received (i)	TRANSFER OF ENERGY MegaWatt Hours Delivered (j)	Line No.
7/8	MDSK	LAGRANDE		451	451	1
7/8	MDSK	LOLO		50	50	2
7/8	OBBLPR	LAGRANDE		135	135	3
7/8	SMLK	M345		1,082	1,082	4
7/8	SMLK	M345		4,192	4,192	5
7/8						6
7/8	BPAT.NWMT	LAGRANDE		15	15	7
7/8	BRDY	IPCO		1,800	1,800	8
7/8	BRDY	IPCOEAST		150	150	9
7/8	BRDY	LAGRANDE		2,082	2,082	10
7/8	HMWY	BRDY		1,340	1,340	11
7/8	HMWY	M345		950	950	12
7/8	JEFF	BRDY		210	210	13
7/8	JEFF	LAGRANDE		447	447	14
7/8	LOLO	BRDY		175	175	15
7/8	M345	BRDY		100	100	16
7/8						17
7/8	BPAT.NWMT	M345		100	100	18
7/8	BRDY	LAGRANDE		167	167	19
7/8	BRDY	M345		250	250	20
7/8	JEFF	M345		900	900	21
7/8	BPAT.NWMT	BORA		4,972	4,972	22
7/8	BPAT.NWMT	BORA		400	400	23
7/8	BPAT.NWMT	M345		2,368	2,368	24
7/8	BPAT.NWMT	M345		11,713	11,713	25
7/8	BRDY	BPAT.NWMT		545	545	26
7/8	BRDY	HMWY		25	25	27
7/8	BRDY	LAGRANDE		1,182	1,182	28
7/8	HMWY	BORA		190	190	29
7/8	HMWY	BRDY		161	161	30
7/8	HMWY	M345		50	50	31
7/8	LAGRANDE	BORA		270	270	32
7/8	LAGRANDE	BRDY		7,444	7,444	33
						34
			0	5,920,350	5,920,350	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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	The Energy Authority, Inc.	Bonneville Power Administration	Sierra Pacific Power	NF
2	The Energy Authority, Inc.	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
3	The Energy Authority, Inc.	Sierra Pacific Power	PacifiCorp East	NF
4	The Energy Authority, Inc.	Sierra Pacific Power	Bonneville Power Administration	NF
5	The Energy Authority, Inc.			AD
6	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp East	Idaho Power Company	NF
7	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp East	Bonneville Power Administration	NF
8	Transalta Energy Marketing (U.S.) Inc.	Idaho Power Company	PacifiCorp East	NF
9	Transalta Energy Marketing (U.S.) Inc.	Idaho Power Company	Sierra Pacific Power	NF
10	Transalta Energy Marketing (U.S.) Inc.	Bonneville Power Administration	PacifiCorp East	NF
11	Transalta Energy Marketing (U.S.) Inc.	Bonneville Power Administration	Sierra Pacific Power	NF
12	Transalta Energy Marketing (U.S.) Inc.	Avista	PacifiCorp East	NF
13	Transalta Energy Marketing (U.S.) Inc.	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
14	Transalta Energy Marketing (U.S.) Inc.	Sierra Pacific Power	Bonneville Power Administration	NF
15	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp West	PacifiCorp East	NF
16	Transalta Energy Marketing (U.S.) Inc.			AD
17	Utah Associated Municipal Power	PacifiCorp East	Sierra Pacific Power	NF
18	Utah Associated Municipal Power			AD
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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.
7/8	LAGRANDE	M345		1,493	1,493	1
7/8	M345	BPAT.NWMT		202	202	2
7/8	M345	BRDY		45	45	3
7/8	M345	LAGRANDE		504	504	4
7/8						5
7/8	BORA	HMWY		292	292	6
7/8	BORA	LAGRANDE		1,136	1,136	7
7/8	HMWY	BORA		36,005	36,005	8
7/8	HMWY	M345		906	906	9
7/8	LAGRANDE	BORA		3,324	3,324	10
7/8	LAGRANDE	M345		2,407	2,407	11
7/8	LOLO	BORA		150	150	12
7/8	M345	BPAT.NWMT		165	165	13
7/8	M345	LAGRANDE		1,550	1,550	14
7/8	SMLK	BORA		575	575	15
7/8						16
7/8	BORA	M345		4,288	4,288	17
7/8						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			0	**5,920,350**	**5,920,350**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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.
1,356,463	134,488		1,490,951	1
-3,155			-3,155	2
1,450,555	84,591		1,535,146	3
-1,609			-1,609	4
4,870,927	479,709		5,350,636	5
-10,878			-10,878	6
8,391	1,032		9,423	7
-19			-19	8
	15,217		15,217	9
54,752			54,752	10
	65,123		65,123	11
	6		6	12
	7,766		7,766	13
	8,096		8,096	14
				15
				16
				17
	269,445		269,445	18
	941,105		941,105	19
	3,776,788		3,776,788	20
	766,651		766,651	21
	2,294,437		2,294,437	22
				23
	643		643	24
	5,808		5,808	25
	1,128		1,128	26
	3,292		3,292	27
	45,877		45,877	28
	13,547		13,547	29
	8,299		8,299	30
	-482		-482	31
	-13		-13	32
	167		167	33
				34
7,725,427	**16,403,945**	**0**	**24,129,372**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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.
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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.
	481		481	1
	167		167	2
	259		259	3
	13,746		13,746	4
	2,656		2,656	5
	586		586	6
	6,982		6,982	7
	40,014		40,014	8
	167		167	9
	7,371		7,371	10
	5,078		5,078	11
	1,046		1,046	12
	-488		-488	13
	3,210		3,210	14
	1,178		1,178	15
	95		95	16
	3,262		3,262	17
	181,699		181,699	18
	112,245		112,245	19
	1,563		1,563	20
	12,147		12,147	21
	5,145		5,145	22
	2,332		2,332	23
	25,612		25,612	24
	24,877		24,877	25
	20,513		20,513	26
	72		72	27
	2,058		2,058	28
	2,313		2,313	29
	38		38	30
	39,558		39,558	31
	709		709	32
	143,349		143,349	33
				34
7,725,427	**16,403,945**	**0**	**24,129,372**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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.
	14,807		14,807	1
	5,256		5,256	2
	556		556	3
	31,588		31,588	4
	3,064		3,064	5
	511		511	6
	19,182		19,182	7
	5,206		5,206	8
	15,554		15,554	9
	1,094		1,094	10
	1,204		1,204	11
	43,236		43,236	12
	602,695		602,695	13
	5,526		5,526	14
	11,975		11,975	15
	2,157		2,157	16
	7,028		7,028	17
	103,402		103,402	18
	534		534	19
	24,225		24,225	20
	1,403		1,403	21
	1,932		1,932	22
	122		122	23
	446		446	24
	515,144		515,144	25
	728,698		728,698	26
	1,719		1,719	27
	1,586		1,586	28
	305		305	29
	313		313	30
	1,582		1,582	31
	362		362	32
	-9,194		-9,194	33
				34
7,725,427	**16,403,945**	**0**	**24,129,372**	

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.
	7,647		7,647	1
	3,827		3,827	2
	2,839		2,839	3
	5,334		5,334	4
	2,654		2,654	5
	21,739		21,739	6
	2,736		2,736	7
	-67		-67	8
	31,277		31,277	9
	5,446		5,446	10
	6,118		6,118	11
	351		351	12
	7,755		7,755	13
	16,403		16,403	14
	58,315		58,315	15
	4,042		4,042	16
	119,847		119,847	17
	998,262		998,262	18
	15,905		15,905	19
	6,462		6,462	20
	1,601		1,601	21
	40,963		40,963	22
	8,231		8,231	23
	373		373	24
	29,238		29,238	25
	36,365		36,365	26
	1,129,176		1,129,176	27
	11,966		11,966	28
	16,366		16,366	29
	64,470		64,470	30
	-12,044		-12,044	31
	1,030		1,030	32
	6,879		6,879	33
				34
7,725,427	**16,403,945**	**0**	**24,129,372**	

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.
	8		8	1
	824		824	2
	412		412	3
	42,822		42,822	4
	6,323		6,323	5
	16,065		16,065	6
	470		470	7
	309		309	8
	5,911		5,911	9
	4,033		4,033	10
	3,349		3,349	11
	206		206	12
	1,335		1,335	13
	-540		-540	14
	348		348	15
	2,347		2,347	16
	367		367	17
	2,406		2,406	18
	137		137	19
	967		967	20
	843		843	21
	7,140		7,140	22
	11,976		11,976	23
	2,695		2,695	24
	197		197	25
	4,638		4,638	26
	33,346		33,346	27
	253,420		253,420	28
	976		976	29
	188		188	30
	13,057		13,057	31
	11,137		11,137	32
	218,342		218,342	33
				34
7,725,427	**16,403,945**	**0**	**24,129,372**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/Q4

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

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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.
	58,205		58,205	1
	7,287		7,287	2
	28,195		28,195	3
	11,613		11,613	4
	4,148		4,148	5
	275		275	6
	203,832		203,832	7
	16,439		16,439	8
	104,246		104,246	9
	225		225	10
	1,215		1,215	11
	115		115	12
	270		270	13
	71,697		71,697	14
	16,627		16,627	15
	124		124	16
	260,006		260,006	17
	1,219		1,219	18
	4,056		4,056	19
	990		990	20
	68,159		68,159	21
	34,822		34,822	22
	573		573	23
	532		532	24
	229		229	25
	12,668		12,668	26
	13,763		13,763	27
	632		632	28
	2,970		2,970	29
	-3,506		-3,506	30
	8		8	31
	300		300	32
	67		67	33
				34
7,725,427	**16,403,945**	**0**	**24,129,372**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/Q4

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

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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.
	8		8	1
	515		515	2
	6,536		6,536	3
	10,449		10,449	4
	5		5	5
	185		185	6
	782		782	7
	367		367	8
	5		5	9
	140		140	10
	1		1	11
	28		28	12
	99		99	13
	179		179	14
	158		158	15
	137		137	16
	9		9	17
	15,006		15,006	18
	185		185	19
	9		9	20
	10		10	21
	1,164		1,164	22
	2,509		2,509	23
	35		35	24
	2,924		2,924	25
	830		830	26
	11		11	27
	1,652		1,652	28
	11,822		11,822	29
	20,090		20,090	30
	8		8	31
	38		38	32
	668		668	33
				34
7,725,427	**16,403,945**	**0**	**24,129,372**	

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.
	69		69	1
	8		8	2
	21		21	3
	164		164	4
	637		637	5
	-6,180		-6,180	6
	69		69	7
	8,306		8,306	8
	692		692	9
	9,608		9,608	10
	6,184		6,184	11
	4,384		4,384	12
	969		969	13
	2,063		2,063	14
	808		808	15
	461		461	16
	-807		-807	17
	465		465	18
	776		776	19
	1,162		1,162	20
	4,182		4,182	21
	22,334		22,334	22
	1,797		1,797	23
	10,637		10,637	24
	52,615		52,615	25
	2,448		2,448	26
	112		112	27
	5,310		5,310	28
	853		853	29
	723		723	30
	225		225	31
	1,213		1,213	32
	33,438		33,438	33
				34
7,725,427	**16,403,945**	**0**	**24,129,372**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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.
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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.
	6,707		6,707	1
	907		907	2
	202		202	3
	2,264		2,264	4
	-56		-56	5
	1,188		1,188	6
	4,620		4,620	7
	146,443		146,443	8
	3,685		3,685	9
	13,520		13,520	10
	9,790		9,790	11
	610		610	12
	671		671	13
	6,304		6,304	14
	2,339		2,339	15
	-520		-520	16
	17,587		17,587	17
	-165		-165	18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
7,725,427	**16,403,945**	**0**	**24,129,372**	

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

9, Open Access Transmission Tariff, Schedule 9 Network Integration Transmission Service

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

The network service agreement between Idaho Power and the Bonneville Power Administration for the Oregon Trail Electric Cooperative expires September 30, 2028. The billing demand for network service is the customer's demand at the time of Idaho Power Company transmission system peak and varies by month.

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

Rate refund for October 2014 thru December 2014, per revised Informational Filing posted 12/22/15.

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

The network service agreement between Idaho Power and the Bonneville Power Administration for the United States Bureau of Reclamation expires December 31, 2023. The billing demand for network service is the customer's demand at the time of Idaho Power Company transmission system peak and varies by month.

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

Rate refund for October 2014 thru December 2014, per revised Informational Filing posted 12/22/15.

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 October 2014 thru December 2014, per revised Informational Filing posted 12/22/15.

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

The contract between Idaho Power and PacifiCorp - Imnaha expires on March 31, 2016. The billing demand for network service is the customer's demand at the time of Idaho Power Company transmission system peak and varies by month.

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

Rate refund for October 2014 thru December 2014, per revised Informational Filing posted 12/22/15.

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

Legacy, contract prior to the Open Access Transmission Tariff

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

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

Schedule Page: 328 Line No.: 10 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.: 11 Column: e

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

Schedule Page: 328 Line No.: 11 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.: 12 Column: e

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

Schedule Page: 328 Line No.: 12 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.: 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.

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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) 04/15/2016	Year/Period of Report 2015/Q4

FOOTNOTE DATA

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: h
Rate refund for October 2014 thru December 2014, per revised Informational Filing posted 12/22/15.

Schedule Page: 328 Line No.: 17 Column: e
7/8, Open Access Transmission Tariff, Schedule 7/8 Point-to-Point Transmission Service

Schedule Page: 328 Line No.: 17 Column: h
Legacy agreement providing OATT-like service, but billed under 454 Facilities revenue.

Schedule Page: 328 Line No.: 31 Column: h
Rate refund for October 2014 thru December 2014, per revised Informational Filing posted 12/22/15.

Schedule Page: 328 Line No.: 32 Column: h
Rate refund for October 2014 thru December 2014, per revised Informational Filing posted 12/22/15.

Schedule Page: 328.1 Line No.: 13 Column: h
Rate refund for October 2014 thru December 2014, per revised Informational Filing posted 12/22/15.

Schedule Page: 328.2 Line No.: 33 Column: h
Rate refund for October 2014 thru December 2014, per revised Informational Filing posted 12/22/15.

Schedule Page: 328.3 Line No.: 8 Column: h
Rate refund for October 2014 thru December 2014, per revised Informational Filing posted 12/22/15.

Schedule Page: 328.3 Line No.: 31 Column: h
Rate refund for October 2014 thru December 2014, per revised Informational Filing posted 12/22/15.

Schedule Page: 328.4 Line No.: 14 Column: h
Rate refund for October 2014 thru December 2014, per revised Informational Filing posted 12/22/15.

Schedule Page: 328.5 Line No.: 30 Column: h
Rate refund for October 2014 thru December 2014, per revised Informational Filing posted 12/22/15.

Schedule Page: 328.7 Line No.: 6 Column: h
Rate refund for October 2014 thru December 2014, per revised Informational Filing posted 12/22/15.

Schedule Page: 328.7 Line No.: 17 Column: h
Rate refund for October 2014 thru December 2014, per revised Informational Filing posted 12/22/15.

Schedule Page: 328.8 Line No.: 5 Column: h
Rate refund for October 2014 thru December 2014, per revised Informational Filing posted 12/22/15.

Schedule Page: 328.8 Line No.: 16 Column: h
Rate refund for October 2014 thru December 2014, per revised Informational Filing posted 12/22/15.

Schedule Page: 328.8 Line No.: 18 Column: h
Rate refund for October 2014 thru December 2014, per revised Informational Filing posted 12/22/15.

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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	29,184	29,184		214,621		214,621
2	Avista Corp-WWP Div	SFP	144,542	144,542		802,613		802,613
3	Avista Corp-WWP Div	OS					-802	-802
4	Bonneville Power Admin	LFP	179,776	179,776		3,200,575		3,200,575
5	Bonneville Power Admin	SFP	321,574	321,574		24,107		24,107
6	Bonneville Power Admin	NF	540	540		2,473		2,473
7	Bonneville Power Admin	OS					15,312	15,312
8	Bonneville Power Admin	OS					521,220	521,220
9	Bonneville Power Adminn	AD					29,754	29,754
10	Bonneville Power Adminn	AD					-48,769	-48,769
11	Bonneville Power Adminn	OS	811	811				
12	Exelon Generation Co	OS					-65,522	-65,522
13	Iberdrola Renewables	OS					-3,087	-3,087
14	Morgan Stanley Capital	OS					-725	-725
15	Nevada Power Company	SFP	14,850	14,850		132,500		132,500
16	Nevada Power Company	NF	328	328		2,150		2,150
	TOTAL		918,343	918,343		5,914,531	364,602	6,279,133

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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	Nevada Power Company	OS					19,540	19,540
2	NextEra Energy	OS					-3,522	-3,522
3	NorthWestern Energy	NF	7,775	7,775		74,353		74,353
4	NorthWestern Energy	SFP	1,985	1,985		10,509		10,509
5	NorthWestern Energy	OS					4,410	4,410
6	PacifiCorp Inc.	LFP	63,546	63,546		928,749		928,749
7	PacifiCorp Inc.	NF	38,104	38,104		208,077		208,077
8	PacifiCorp Inc.	SFP	115,328	115,328		125,584		125,584
9	PacifiCorp Inc.	OS					-2,048	-2,048
10	PacifiCorp Inc.	OS					-65,539	-65,539
11	PacifiCorp Inc.	OS					28	28
12	PacifiCorp Inc.	OS					58,436	58,436
13	Powerex Corp.	OS					-57,056	-57,056
14	Puget Sound Energy, Inc	SFP				187,620		187,620
15	Shell Energy N. America	SFP				600		600
16	Shell Energy N. America	OS					-1,736	-1,736
	TOTAL		918,343	918,343		5,914,531	364,602	6,279,133

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	TransAlta Energy U.S.	OS					-35,292	-35,292
2								
3								
4								
5								
6								
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		918,343	918,343		5,914,531	364,602	6,279,133

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

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

Schedule Page: 332 Line No.: 7 Column: a
Spinning/Supplemental Reserves

Schedule Page: 332 Line No.: 8 Column: a
Ancillary Services

Schedule Page: 332 Line No.: 9 Column: a
Correction of refund for System Control and Dispatch Charges in 2013

Schedule Page: 332 Line No.: 10 Column: a
Refund of Adjustment for System Control and Dispatch Charges.

Schedule Page: 332 Line No.: 11 Column: a
BPAT is provider for transmission services settled with PSEMKT.

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: a
Resale Transmission

Schedule Page: 332.1 Line No.: 1 Column: a
Ancillary Services

Schedule Page: 332.1 Line No.: 5 Column: a
Ancillary Services

Schedule Page: 332.1 Line No.: 6 Column: b
Contract Expiration Date 05/31/2019.

Schedule Page: 332.1 Line No.: 11 Column: a
Energy Imbalance Market

Schedule Page: 332.1 Line No.: 12 Column: a
Ancillary Services

Schedule Page: 332.1 Line No.: 13 Column: a
Resale Transmission

Schedule Page: 332.1 Line No.: 14 Column: a
BPAT is provider for transmission services settled with PSEMKT

Schedule Page: 332.1 Line No.: 16 Column: a
Resale Transmission

Schedule Page: 332.2 Line No.: 1 Column: a
Resale Transmission

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	505,604
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	1,602,436
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	64,833
6		
7	Director Fees and Expenses:	
8	Christine King	88,359
9	Dennis Johnson	70,290
10	J Lamont Keen	64,350
11	Jan Packwood	26,812
12	Joan Smith	35,395
13	Judith Johansen	78,331
14	Richard Dahl	91,575
15	Richard Navarro	65,066
16	Robert Tintsman	170,775
17	Ronald Jibson	74,473
18	Thomas Carlile	76,230
19	Thomas Wilford	30,571
20		
21	Corporate Memberships and Subscriptions:	
22	Arizona State University	50,000
23	Associated Taxpayers of Idaho	22,000
24	Boston College for Corporations	5,000
25	Business Plus	5,000
26	Ceati International	13,350
27	Corporate Executive Board	87,535
28	Idaho Association of Commerce & Industry	15,000
29	Idaho Technology Council	12,500
30	National Association of Directors	7,125
31	National Hydropower Association	36,069
32	North American Energy Standard	7,000
33	Northwest Power Pool	342,472
34	Pacific NW Utilities	40,160
35	SNL Financial Unlimited Subscription	23,200
36	Western Alliance for Economic	2,500
37	Western Energy Coordinating Council	1,604,339
38	Western Energy Institute	30,794
39	Misc Memberships Under $2,000	5,574
40		
41	Chambers of Commerce & Other Civic Organizations	
42		90,135
43		
44		
45		
46	TOTAL	5,444,853

FOOTNOTE DATA

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

Recipient	Purpose	Amount
American Stock Transfer & Trust	Mgmt Services	$ 65,293
Bloomberg Finance LP	Misc Expense	10,146
Broadridge Financial Solutions	Misc Expense	46,949
Deutsche Bank	Broker Fees	30,000
E Source	Mgmt Services	39,906
Moody's Analytics	Mgmt Services	32,310
NASDAQ Corp Solutions	Mgmt Services	62,573
New York Stock Exchange	Listing Services	50,163
Payroll Related Expenses	Misc Expense	175,051
PR Newswire	Misc Expense	14,813
Rivel Research Group	Mgmt Services	15,840
Stock Based Compensation	Misc Expense	949,993
Wells Fargo Shareowner Services	Mgmt Services	107,626
Miscellaneous under $5,000	Misc Expense	1,773
		$ 1,602,436

Schedule Page: 335 Line No.: 5 Column: b

Recipient	Purpose	Amount
Bank of New York	Revenue Bonds	$ 13,925
Payroll Related Expense	Misc Expense	22,311
Total Electric	Misc Expense	5,175
Union Bank	Revenue Bonds	9,680
Miscellaneous under $5,000	Misc Expense	13,742
		$ 64,833

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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			7,095,926		7,095,926
2	Steam Production Plant	25,480,959	549,017			26,029,976
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	14,513,923				14,513,923
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	17,072,839				17,072,839
7	Transmission Plant	20,991,260				20,991,260
8	Distribution Plant	41,882,379				41,882,379
9	Regional Transmission and Market Operation					
10	General Plant	10,440,768				10,440,768
11	Common Plant-Electric					
12	TOTAL	130,382,128	549,017	7,095,926		138,027,071

B. Basis for Amortization Charges

Acct 404	Balance 1/1/2015	2015 Amortization	Balance 12/31/2015	Remaining Months
(1)	36,000	12,000	24,000	24
(2)	10,339,996	545,446	9,794,550	-
(3)	5,251,629	189,064	5,062,565	321
(4)	15,747,708	6,035,788	13,191,811	-
(5)	3,747,997	287,899	3,460,098	156
(6)	201,821	8,026	193,795	-
(7)	604,625	17,702	878,552	-
	---------------	--------------	----------------	
Total	35,929,777	7,095,926	32,605,372	

(1) Shoshone-Bannock Tribe License & Use Agreement(Termination date December 31, 2023).
(2) Middle Snake Relicesing Costs (Amortized over a 30 year license period).
(3) Swan Falls Relicesing Costs (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 Compliance Costs (Termination date will be expiration date of the FERC Licenses)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	310.20	657	75.00		3.63	R4.0	20.20
13	311.00	153,408	100.00	-10.00	1.84	S1.0	21.30
14	312.10	133,426	60.00	-5.00	1.15	R3.0	21.80
15	312.20	545,122	60.00	-5.00	2.77	R1.5	20.90
16	312.30	4,341	25.00	20.00	2.36	R3.0	7.90
17	314.00	162,544	45.00	-5.00	3.25	S1.0	19.40
18	315.00	70,702	60.00		1.44	S1.5	19.80
19	316.00	12,808	45.00	-5.00	3.75	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	0.87	L2.0	7.90
22	316.50	310	12.00	15.00	5.60	L2.0	5.10
23	316.60	106	20.00	15.00	4.39	L2.0	18.00
24	316.70	80	20.00	15.00	2.09	L2.0	14.40
25	316.80	3,855	20.00	30.00	3.52	O1.0	16.60
26	316.90	14	35.00	15.00	2.45	S1.0	34.70
27	317.00	13,930					
28	Subtotal Steam	1,101,634					
29	331.00	175,996	105.00	-25.00	2.40	R2.5	33.00
30	332.10	19,460	95.00	-20.00	1.31	S4.0	39.80
31	332.20	245,027	95.00	-20.00	1.65	S4.0	35.60
32	332.30	5,472			1.44	SQUARE	49.10
33	333.00	211,679	80.00	-5.00	1.73	R3.0	32.60
34	334.00	58,474	50.00	-5.00	2.75	R1.5	26.10
35	335.00	22,054	95.00		2.28	R2.0	28.10
36	335.10	88	15.00		6.77	SQUARE	6.50
37	335.20	366	20.00		5.57	SQUARE	5.30
38	335.30	288	5.00		12.90	SQUARE	3.30
39	336.00	10,881	75.00		2.22	R3.0	21.40
40	Subtotal Hydro	749,785					
41	341.00	142,711			2.89	SQUARE	27.20
42	342.00	10,453	50.00		2.98	S2.5	28.50
43	343.00	218,961	40.00		3.46	S1.5	25.90
44	344.00	66,532	45.00		2.45	S2.0	26.80
45	345.00	91,099	50.00		3.23	S1.5	22.60
46	346.00	6,010	35.00		3.40	R2.5	24.50
47	Subtotal Other	535,766					
48	350.20	31,780	70.00		1.39	R3.0	58.50
49	350.22	171	30.00		2.93		
50	352.00	77,780	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	04/15/2016	End of 2015/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	407,603	50.00	-5.00	1.90	R1.5	40.70
13	354.00	184,628	65.00	-15.00	1.65	S3.0	50.80
14	355.00	157,531	60.00	-70.00	2.70	R2.0	43.60
15	355.10	849	10.00		7.78		
16	356.00	211,905	65.00	-40.00	2.19	R2.0	48.50
17	359.00	390	65.00		0.79	R2.5	24.00
18	Subtotal Transmission	1,072,637					
19	360.22	476	30.00		3.49		30.00
20	361.00	34,175	65.00	-40.00	2.13	R2.5	53.30
21	362.00	216,854	50.00	-5.00	1.98	R1.0	40.20
22	364.00	244,791	44.00	-45.00	3.06	R1.5	31.30
23	364.10	2,195	12.00		7.55		
24	365.00	129,331	45.00	-35.00	2.96	R0.5	33.60
25	366.00	48,323	60.00	-20.00	1.93	R2.0	48.40
26	367.00	230,143	46.00	-15.00	2.23	R2.0	35.30
27	368.00	515,652	35.00	-3.00	2.57	R1.0	27.00
28	369.00	58,771	40.00	-40.00	2.54	R2.0	29.50
29	370.00	16,979	22.00	1.00	3.46	O1.0	17.50
30	370.10	68,269	15.00		6.88	S2.5	13.10
31	371.10		12.00	-2.00		S4.0	9.00
32	371.20	2,954	17.00	-2.00	1.51	R1.5	14.70
33	373.20	4,543	30.00	-25.00	2.41	R1.0	20.60
34	374.00	164					
35	Subtotal Distribution	1,573,620					
36	390.11	29,421	100.00	-5.00	2.57	S0.5	28.80
37	390.12	81,504	55.00	-5.00	1.89	S0.5	44.30
38	390.20		35.00		3.94	S3.0	25.70
39	391.10	14,155	20.00		2.92	SQUARE	12.90
40	391.20	24,594	5.00		11.73	SQUARE	3.20
41	391.21	7,944	8.00		11.50	L2.0	5.70
42	392.10	822	12.00	15.00	7.39	L2.0	8.90
43	392.30	4,563	10.00	50.00	2.06	S2.5	3.40
44	392.40	23,290	12.00	15.00	7.03	L2.0	6.80
45	392.50	1,127	12.00	15.00	3.33	L2.0	9.00
46	392.60	34,103	20.00	15.00	4.03	L2.0	13.40
47	392.70	6,944	20.00	15.00	3.12	L2.0	12.50
48	392.90	5,031	35.00	15.00	2.05	S1.0	24.30
49	393.00	2,255	25.00		3.18	SQUARE	19.40
50	394.00	8,022	20.00		4.14	SQUARE	13.30

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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	395.00	12,704	20.00		4.31	SQUARE	12.10
13	396.00	15,082	20.00	30.00	1.57	O1.0	17.60
14	397.10	4,672	15.00		4.41	SQUARE	8.30
15	397.20	30,517	15.00		5.44	SQUARE	9.80
16	397.30	3,472	15.00		6.03	SQUARE	8.00
17	397.40	16,754	10.00		7.44	SQUARE	6.50
18	398.00	5,968	15.00		5.19	SQUARE	10.60
19	Subtotal General	332,944					
20	Total Plant	5,366,386					
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Schedule Page: 336 Line No.: 28 Column: a

Steam, hydro, and other production depreciation and amortization of certain electric plant is maintained by plant location. Effective April 1, 1993 the forecast life span method of life analysis using an interim retirement rate was utilized to develop all production plant rates. Rates, Service lives, net salvage and remaining lives indicated are on a composite basis. An average plant balance was used in computing these rates by FERC account. Effective April 1, 1993 all depreciable plant is being depreciated using the straight-line life method.

Schedule Page: 336 Line No.: 40 Column: a

Steam, hydro, and other production depreciation and amortization of certain electric plant is maintained by plant location. Effective April 1, 1993 the forecast life span method of life analysis using an interim retirement rate was utilized to develop all production plant rates. Rates, Service lives, net salvage and remaining lives indicated are on a composite basis. An average plant balance was used in computing these rates by FERC account. Effective April 1, 1993 all depreciable plant is being depreciated using the straight-line life method.

Schedule Page: 336 Line No.: 47 Column: a

Steam, hydro, and other production depreciation and amortization of certain electric plant is maintained by plant location. Effective April 1, 1993 the forecast life span method of life analysis using an interim retirement rate was utilized to develop all production plant rates. Rates, Service lives, net salvage and remaining lives indicated are on a composite basis. An average plant balance was used in computing these rates by FERC account. Effective April 1, 1993 all depreciable plant is being depreciated using the straight-line life method.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/Q4

REGULATORY COMMISSION EXPENSES

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

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	Federal Energy Regulatory Commission:				
2	Annual admin charges assessed by FERC	3,306,791		3,306,791	
3					
4	General Regulatory Expenses and				
5	Various other Dockets		17,061	17,061	
6					
7	Oregon Hydro - Fees Amortization	158,501		158,501	
8					
9	Regulatory Commission Expenses - Idaho				
10	Rate Case - Misc expenses		1,066	1,066	
11					
12	Regulatory Commission Expenses - Oregon				
13	Rate Case - Misc expenses		138	138	
14	General Regulatory		111,541	111,541	
15	Other OPUC expenses		21,159	21,159	
16					
17					
18					
19					
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45					
46	TOTAL	3,465,292	150,965	3,616,257	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/Q4

REGULATORY COMMISSION EXPENSES (Continued)

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

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO			Deferred to Account 182.3	Contra Account	Amount	Deferred in Account 182.3 End of Year	Line No.
Department (f)	Account No. (g)	Amount (h)	(i)	(j)	(k)	(l)	
							1
Electric	928	3,306,791					2
							3
							4
Electric	928	17,061					5
							6
Electric	928	158,501					7
							8
							9
Electric	928	1,066					10
							11
							12
Electric	928	138					13
Electric	928	111,541					14
Electric	928	21,159					15
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		3,616,257					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	04/15/2016	End of 2015/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 2015.	
3		
4		
5		
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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) 04/15/2016	Year/Period of Report End of 2015/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	04/15/2016	End of 2015/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	23,391,734		
4	Transmission	7,150,122		
5	Regional Market			
6	Distribution	19,443,315		
7	Customer Accounts	11,146,099		
8	Customer Service and Informational	5,063,852		
9	Sales			
10	Administrative and General	45,969,645		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	112,164,767		
12	Maintenance			
13	Production	4,962,423		
14	Transmission	3,482,962		
15	Regional Market			
16	Distribution	8,340,987		
17	Administrative and General	963,324		
18	TOTAL Maintenance (Total of lines 13 thru 17)	17,749,696		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	28,354,157		
21	Transmission (Enter Total of lines 4 and 14)	10,633,084		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	27,784,302		
24	Customer Accounts (Transcribe from line 7)	11,146,099		
25	Customer Service and Informational (Transcribe from line 8)	5,063,852		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	46,932,969		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	129,914,463		129,914,463
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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			
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)	129,914,463		129,914,463
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	5,289,704		5,289,704
79	Other Clearing Accounts	3,200,159		3,200,159
80	Construction Work in Progress	57,439,811		57,439,811
81	Other Work in Progress	3,287,058		3,287,058
82	Paid Absences	23,344,477		23,344,477
83	Preliminary Survey and Investigation	4,463		4,463
84	Other Accounts	5,389,068		5,389,068
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	97,954,740		97,954,740
96	TOTAL SALARIES AND WAGES	227,869,203		227,869,203

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/Q4

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			563,957			
2	Reactive Supply and Voltage			39,649			
3	Regulation and Frequency Response				3,202,871	KW	313,721
4	Energy Imbalance				-2,946	KWH	-15,107
5	Operating Reserve - Spinning			7,991	4,154,060	KW	406,890
6	Operating Reserve - Supplement			7,321	4,154,060	KW	406,890
7	Other						
8	Total (Lines 1 thru 7)			618,918	11,508,045		1,112,394

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) X An Original (2) _ A Resubmission	04/15/2016	2015/Q4

FOOTNOTE DATA

Schedule Page: 398 Line No.: 8 Column: b

Idaho Power does not systematically record the number of units related to ancillary services purchased.

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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	4,700	2	1000	3,850	242	463		145	
2	February	4,275	19	800	3,137	184	463		491	
3	March	4,422	5	800	3,326	211	463		422	
4	Total for Quarter 1				10,313	637	1,389		1,058	
5	April	4,476	21	1900	3,396	259	463		358	
6	May	4,719	4	2100	3,533	285	463		438	
7	June	5,934	26	1700	4,818	373	463		280	
8	Total for Quarter 2				11,747	917	1,389		1,076	
9	July	6,016	1	1800	4,979	376	463		198	
10	August	5,623	13	1500	4,458	307	463		395	
11	September	5,048	1	2000	4,070	293	463		222	
12	Total for Quarter 3				13,507	976	1,389		815	
13	October	4,281	10	1700	3,375	170	463		273	
14	November	3,208	30	1900	2,103	234	773		98	
15	December	3,257	1	800	1,851	244	773		389	
16	Total for Quarter 4				7,329	648	2,009		760	
17	Total Year to Date/Year				42,896	3,178	6,176		3,709	

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

Firm Network Service for Self, 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 resulted in the elimination of 1836 MW of contract demand that is associated with the pre-Order No. 888 transmission agreements that terminate upon closing of the transaction. The Parties received all required regulatory approvals and the transaction closed October 30, 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	04/15/2016	End of 2015/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)	14,264,493
3	Steam	4,676,370			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	
5	Hydro-Conventional	5,909,916			
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	1,254,136
7	Other	2,075,731			
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	12,662,017	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
10	Purchases	3,788,934	27	Total Energy Losses	1,051,718
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	16,570,347
12	Received	276,510			
13	Delivered	162,239			
14	Net Exchanges (Line 12 minus line 13)	114,271			
15	Transmission For Other (Wheeling)				
16	Received	5,920,350			
17	Delivered	5,915,225			
18	Net Transmission for Other (Line 16 minus line 17)	5,125			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	16,570,347			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/Q4

MONTHLY PEAKS AND OUTPUT

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

NAME OF SYSTEM: Idaho Power Company

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	1,429,454	162,212	2,168	2	9 AM
30	February	1,215,125	205,779	1,993	23	8 AM
31	March	1,214,436	167,129	1,919	4	8 AM
32	April	1,212,235	35,621	1,997	28	10 PM
33	May	1,304,647	103,313	2,156	4	8 PM
34	June	1,718,107	62,532	3,402	30	4 PM
35	July	1,747,644	109,737	3,360	1	7 PM
36	August	1,644,547	30,741	3,221	12	6 PM
37	September	1,270,259	62,870	2,473	1	7 PM
38	October	1,186,337	138,462	1,814	10	6 PM
39	November	1,209,550	66,026	2,203	30	7 PM
40	December	1,418,006	109,714	2,241	1	8 AM
41	TOTAL	16,570,347	1,254,136			

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

Page 329 Column I differs from page 401 by 5,125 MWH, reported for Lucky Peak variation and BPA Energy imbalance schedules on page 401. The numbers that are shown on pages 328-330 are for account 456 wheeling only, the numbers on page 401 have to be adjusted for account 447 transmission.

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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)	727			64		
7	Plant Hours Connected to Load	8760			5017		
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	4096050000			182941000		
13	Cost of Plant: Land and Land Rights	517720			106610		
14	Structures and Improvements	70396751			12492016		
15	Equipment Costs	546181648			63613298		
16	Asset Retirement Costs	9755694			4431431		
17	Total Cost	626851813			80643355		
18	Cost per KW of Installed Capacity (line 17/5) Including	813.5650			1256.1270		
19	Production Expenses: Oper, Supv, & Engr	234643			397405		
20	Fuel	116084606			4737072		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	5914375			771734		
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	6301917			393762		
27	Rents	432038			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	109988			12840		
30	Maintenance of Structures	0			87640		
31	Maintenance of Boiler (or reactor) Plant	7602363			223505		
32	Maintenance of Electric Plant	2550850			1967645		
33	Maintenance of Misc Steam (or Nuclear) Plant	6711067			46900		
34	Total Production Expenses	145941847			8638503		
35	Expenses per Net KWh	0.0356			0.0472		
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	2303826	6262	0	111192	1083	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	9173	140000	0	8559	138800	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	48.729	108.869	0.000	39.377	76.795	0.000
41	Average Cost of Fuel per Unit Burned	50.038	90.059	0.000	41.435	105.956	0.000
42	Average Cost of Fuel Burned per Million BTU	2.722	15.316	0.000	2.464	18.182	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.028	0.000	0.000	0.026	0.000	0.000
44	Average BTU per KWh Net Generation	10347.000	0.000	0.000	10255.000	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	04/15/2016	End of 2015/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
		262			252			185	6
		7664			1538			1023	7
		0			261			164	8
		0			0			0	9
		0			0			0	10
		0			8			4	11
		249740000			255025000			157875000	12
		1106140			402745			0	13
		70519961			6087725			1688442	14
		323843957			100153211			51991319	15
		-257063			0			0	16
		395212995			106643681			53679761	17
		1394.0494			393.6644			310.6468	18
		655838			192181			12812	19
		10464678			9729462			6071381	20
		0			0			0	21
		3105502			0			0	22
		0			0			0	23
		0			0			0	24
		1262175			539906			471697	25
		-19410			311203			152790	26
		0			0			0	27
		0			0			0	28
		4165			0			0	29
		790432			134240			135606	30
		6035691			2151			5795	31
		894058			246946			234934	32
		165285			0			0	33
		23358414			11156089			7085015	34
		0.0935			0.0437			0.0449	35
Coal	Oil		Gas			Gas			36
Tons	Barrels		MCF			MCF			37
139920	12293	0	2547925	0	0	1601807	0	0	38
11398	138778	0	1027	0	0	1027	0	0	39
36.239	88.175	0.000	3.819	0.000	0.000	3.790	0.000	0.000	40
67.361	83.462	0.000	3.819	0.000	0.000	3.790	0.000	0.000	41
3.725	14.319	0.000	3.200	0.000	0.000	3.180	0.000	0.000	42
0.042	0.000	0.000	0.038	0.000	0.000	0.038	0.000	0.000	43
10419.000	0.000	0.000	10261.000	0.000	0.000	10420.000	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	04/15/2016	End of 2015/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)	301	0
7	Plant Hours Connected to Load	6132	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	22	0
12	Net Generation, Exclusive of Plant Use - KWh	1662770000	0
13	Cost of Plant: Land and Land Rights	2287261	0
14	Structures and Improvements	134922940	0
15	Equipment Costs	240012947	0
16	Asset Retirement Costs	0	0
17	Total Cost	377223148	0
18	Cost per KW of Installed Capacity (line 17/5) Including	1184.5601	0
19	Production Expenses: Oper, Supv, & Engr	310438	0
20	Fuel	39140394	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	3592304	0
26	Misc Steam (or Nuclear) Power Expenses	350000	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	93848	0
31	Maintenance of Boiler (or reactor) Plant	32341	0
32	Maintenance of Electric Plant	788337	0
33	Maintenance of Misc Steam (or Nuclear) Plant	0	0
34	Total Production Expenses	44307662	0
35	Expenses per Net KWh	0.0266	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	11344468	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	3.450	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	3.450	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	2.950	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.024	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	7007.000	0.000	0.000	0.000	0.000	0.000

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	04/15/2016	End of 2015/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)	95	54
7	Plant Hours Connect to Load	6,909	8,727
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	294,308,000	311,673,000
13	Cost of Plant		
14	Land and Land Rights	875,318	768,366
15	Structures and Improvements	11,986,636	1,098,135
16	Reservoirs, Dams, and Waterways	4,293,075	8,963,581
17	Equipment Costs	32,331,624	9,463,703
18	Roads, Railroads, and Bridges	839,276	486,477
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	50,325,929	20,780,262
21	Cost per KW of Installed Capacity (line 20 / 5)	545.2430	277.0702
22	Production Expenses		
23	Operation Supervision and Engineering	209,916	814,397
24	Water for Power	1,530,108	870,028
25	Hydraulic Expenses	136,364	964,512
26	Electric Expenses	83,114	46,371
27	Misc Hydraulic Power Generation Expenses	277,549	449,505
28	Rents	137	3,405
29	Maintenance Supervision and Engineering	8,576	5,976
30	Maintenance of Structures	158,788	44,538
31	Maintenance of Reservoirs, Dams, and Waterways	6,128	67,464
32	Maintenance of Electric Plant	304,393	115,994
33	Maintenance of Misc Hydraulic Plant	67,013	145,737
34	Total Production Expenses (total 23 thru 33)	2,782,086	3,527,927
35	Expenses per net KWh	0.0095	0.0113

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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
534	12	205	6
8,760	7,871	8,760	7
			8
747	15	221	9
220	1	202	10
8	2	6	11
1,719,268,000	31,539,000	750,079,000	12
			13
18,266,595	82,142	1,212,767	14
32,472,875	7,380,842	10,878,167	15
67,619,060	3,145,630	30,432,975	16
61,266,804	13,881,886	19,497,721	17
529,364	122,668	585,876	18
0	0	0	19
180,154,698	24,613,168	62,607,506	20
307.7463	1,981.7366	329.5132	21
			22
810,294	226,686	382,292	23
666,009	228,916	299,516	24
1,228,538	417,474	553,562	25
314,903	107,054	161,460	26
927,272	294,065	415,275	27
111,511	141	18,315	28
25,206	3,216	10,918	29
181,794	12,431	112,661	30
34,061	-9	5,274	31
748,067	64,559	147,767	32
428,623	100,709	341,148	33
5,476,278	1,455,242	2,448,188	34
0.0032	0.0461	0.0033	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	04/15/2016	End of 2015/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)	330	23
7	Plant Hours Connect to Load	8,760	8,760
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	445	25
10	(b) Under the Most Adverse Oper Conditions	137	21
11	Average Number of Employees	5	1
12	Net Generation, Exclusive of Plant Use - Kwh	1,461,432,000	154,194,000
13	Cost of Plant		
14	Land and Land Rights	1,880,381	205,376
15	Structures and Improvements	2,931,900	2,824,126
16	Reservoirs, Dams, and Waterways	52,872,923	6,283,406
17	Equipment Costs	19,960,871	12,088,094
18	Roads, Railroads, and Bridges	922,781	1,542,871
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	78,568,856	22,943,873
21	Cost per KW of Installed Capacity (line 20 / 5)	200.6867	1,053.9216
22	Production Expenses		
23	Operation Supervision and Engineering	472,143	196,895
24	Water for Power	425,145	849,855
25	Hydraulic Expenses	797,610	230,740
26	Electric Expenses	295,711	65,750
27	Misc Hydraulic Power Generation Expenses	575,747	177,704
28	Rents	30,450	0
29	Maintenance Supervision and Engineering	24,842	3,420
30	Maintenance of Structures	36,430	8,347
31	Maintenance of Reservoirs, Dams, and Waterways	244,249	22,262
32	Maintenance of Electric Plant	359,716	35,828
33	Maintenance of Misc Hydraulic Plant	688,719	147,409
34	Total Production Expenses (total 23 thru 33)	3,950,762	1,738,210
35	Expenses per net KWh	0.0027	0.0113

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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
87	22	37	6
8,760	8,747	7,157	7
			8
91	24	53	9
84	14	50	10
5	4	3	11
375,982,000	110,847,000	76,114,000	12
			13
5,476,746	231,584	255,499	14
9,780,013	27,334,904	11,021,547	15
10,807,310	15,989,465	9,000,263	16
14,047,800	31,037,692	21,350,845	17
1,602,868	835,946	1,917,603	18
0	0	0	19
41,714,737	75,429,591	43,545,757	20
503.8012	3,017.1836	825.6685	21
			22
871,100	621,417	195,251	23
963,737	710,027	214,848	24
1,152,655	873,630	127,868	25
50,830	25,464	74,464	26
678,592	557,788	228,498	27
55,646	6,298	3,224	28
6,615	10,795	4,164	29
82,602	126,817	44,281	30
46,467	18,032	55,029	31
196,523	271,370	74,878	32
88,092	258,825	86,230	33
4,192,859	3,480,463	1,108,735	34
0.0112	0.0314	0.0146	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	04/15/2016	End of 2015/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)	36	13
7	Plant Hours Connect to Load	8,760	8,385
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	39	14
10	(b) Under the Most Adverse Oper Conditions	32	11
11	Average Number of Employees	3	2
12	Net Generation, Exclusive of Plant Use - Kwh	203,255,000	74,608,000
13	Cost of Plant		
14	Land and Land Rights	202,398	313,328
15	Structures and Improvements	2,080,266	1,253,635
16	Reservoirs, Dams, and Waterways	6,130,430	10,108,902
17	Equipment Costs	8,923,679	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)	17,366,132	16,431,189
21	Cost per KW of Installed Capacity (line 20 / 5)	503.3661	1,314.4951
22	Production Expenses		
23	Operation Supervision and Engineering	281,120	150,239
24	Water for Power	281,812	161,587
25	Hydraulic Expenses	339,108	90,955
26	Electric Expenses	94,946	45,140
27	Misc Hydraulic Power Generation Expenses	241,563	183,335
28	Rents	0	88
29	Maintenance Supervision and Engineering	5,570	2,778
30	Maintenance of Structures	111,480	24,323
31	Maintenance of Reservoirs, Dams, and Waterways	36,230	987
32	Maintenance of Electric Plant	85,340	79,795
33	Maintenance of Misc Hydraulic Plant	115,278	68,595
34	Total Production Expenses (total 23 thru 33)	1,592,447	807,822
35	Expenses per net KWh	0.0078	0.0108

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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	34	38	6
0	8,758	5,827	7
			8
0	64	61	9
0	60	1	10
0	5	2	11
0	207,416,000	70,756,000	12
			13
114,367	424,428	138,100	14
41,098,277	2,869,695	10,431,584	15
13,556,785	6,920,148	17,431,179	16
2,246,883	8,197,531	29,260,290	17
99,051	88,693	501,877	18
0	0	0	19
57,115,363	18,500,495	57,763,030	20
0.0000	308.3416	971.6237	21
			22
0	270,998	197,687	23
0	298,475	1,477,096	24
7,416,144	347,273	129,881	25
0	125,419	32,689	26
0	286,774	276,779	27
0	2,756	3,295	28
0	3,460	3,964	29
0	79,756	33,558	30
0	11,408	18,432	31
0	44,913	93,791	32
92,248	80,272	102,119	33
7,508,392	1,551,504	2,369,291	34
0.0000	0.0075	0.0335	35

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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	04/15/2016	2015/Q4

FOOTNOTE DATA

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	04/15/2016	End of 2015/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	15,695	3,583,449
3	Thousand Springs	1912	8.80	7.6	52,740	9,566,531
4						
5						
6	Internal Combustion:					
7	Salmon Diesel	1967	5.00	4.0	13	909,259
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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	04/15/2016	End of 2015/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

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

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
1,433,380	238,000		70,444			2
1,087,106	259,879		84,574			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) 04/15/2016	Year/Period of Report 2015/Q4

FOOTNOTE DATA

Schedule Page: 410 Line No.: 7 Column: a

Salmon units are classified as standby.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/Q4

TRANSMISSION LINE STATISTICS

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

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	Borah	Midpoint	345.00	500.00	S Tower	62.35		1
2	Boardman	Slatt	500.00	500.00	S Tower	1.79		1
3	Summer lake	Hemingway	500.00	500.00	S Tower	0.41		1
4	Hemingway	Midpoint	500.00	500.00	S Tower	0.37		1
5	Summer Lake	Hemingway	500.00	500.00	S Tower	53.09		1
6	Hemingway	Midpoint	500.00	500.00	S Tower	47.83		1
7								
8	Jim Bridger	Goshen	345.00	345.00	S Tower	66.13		1
9	State Line	Midpoint	345.00	345.00	S Tower	76.06		2
10	Kinport	Borah	345.00	345.00	S Tower	19.85		1
11	Jim Bridger	Populus	345.00	345.00	S Tower	60.94		1
12	Populus	Kinport	345.00	345.00	S Tower	7.42		1
13	Jim Bridger	Populus	345.00	345.00	S Tower	61.09		1
14	Populus	Borah	345.00	345.00	S Tower	9.05		1
15	Goshen	Kinport	345.00	345.00	S Tower	7.49		1
16	Midpoint	Borah #1	345.00	345.00	H Wood	51.07		1
17	Midpoint	Borah #2	345.00	345.00	H Wood	50.01		2
18	Adelaide Tap	Adelaide	345.00	345.00	H Wood	1.72		2
19								
20	Quartz	LaGrande	230.00	230.00	H Wood	46.27		1
21	Midpoint	Hunt	230.00	230.00	S Tower	0.70		2
22	Brady	Antelope	230.00	230.00	H Wood	56.41		1
23	Brady	Treasureton	230.00	230.00	H Wood	0.11		1
24	Brady #1 & #2	Kinport	230.00	230.00	S Tower	17.94		2
25	Jim Bridger	Point of Rocks	230.00	230.00	H Wood			1
26	Brownlee	Ontario	230.00	230.00	S Tower	72.67		1
27	Mora	Bowmont	138.00	230.00	S P Wood	9.98		1
28	Mora	Bowmont	138.00	230.00	H Wood	8.75		1
29	Jim Bridger	Point of Rocks	230.00	230.00	H Wood			1
30	Caldwell 710	Locust	230.00	230.00	SP Steel	18.60		1
31	Boise Bench	Caldwell	230.00	230.00	S Tower	7.73		1
32	Boise Bench	Caldwell	230.00	230.00	H Wood	33.49		1
33	Boise Bench	Cloverdale	230.00	230.00	S Tower	15.78		2
34	Boardman	Dalreed Sub	230.00	230.00	H Wood	1.67		1
35	Brownlee 714	Oxbow	230.00	230.00	SP Steel	11.04		2
36					TOTAL	4,769.03	11.02	203

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			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)	
1272 ACSR	256,381	15,974,858	16,231,239					1
2X1780 ACSR		446,708	446,708					2
1272 ACSR		603,657	603,657					3
1272 ACSR								4
3X1272 ACSR		17,991,882	17,991,882					5
3X1272 ACSR		16,358,594	16,358,594					6
								7
1272 ACSR	483,309	5,787,895	6,271,204					8
795 ACSR	571,979	11,108,161	11,680,140					9
1272 ACSR	344,220	4,396,928	4,741,148					10
1272 ACSR		9,512,597	9,512,597					11
1272 ACSR								12
1272 ACSR		9,249,735	9,249,735					13
1272 ACSR								14
2X1272 ACSR		514,724	514,724					15
715.5 ACSR	283,143	8,543,370	8,826,513					16
715.5 ACSR	64,851	10,228,542	10,293,393					17
715.5 ACSR	51,448	224,222	275,670					18
								19
795 ACSR	62,218	5,685,245	5,747,463					20
715.5 ACSR	9,145	998,452	1,007,597					21
1272 ACSR	108,301	3,399,123	3,507,424					22
795 ACSR		6,186	6,186					23
715.5 ACSR	18,829	1,080,441	1,099,270					24
1272 ACSR	1,190		1,190					25
2X954 ACSR	1,676,838	20,541,790	22,218,628					26
715.5 ACSR	413,793	2,209,007	2,622,800					27
715.5 ACSR								28
1272 ACSR	1,899		1,899					29
1590 ACSR	2,138,236	8,775,086	10,913,322					30
1272 ACSR	1,748,214	7,631,906	9,380,120					31
715.5 ACSR								32
1272 ACSR	3,062,812	6,560,901	9,623,713					33
795 AAC		89,680	89,680					34
954 ACSR	34,174	16,026,470	16,060,644					35
	32,174,968	555,434,671	587,609,639	8,044,636	3,092,363	3,084,849	14,221,848	36

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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	Caldwell	Ontario	230.00	230.00	H Wood	30.10		1
2	Caldwell	Ontario	230.00	230.00	S Tower	3.14		1
3	Bennett Mtn PP	Rattlesnake TS	230.00	230.00	SP Steel	4.43		1
4	Borah	Hunt	230.00	230.00	H Steel	68.17		1
5	Danskin	Hubbard	230.00	230.00	H Steel	36.30		1
6	Danskin	Hubbard	230.00	230.00	SP Steel	1.84		1
7	Danskin	Hubbard	230.00	230.00	SP Steel	1.30		2
8	Danskin	Bennett Mtn	230.00	230.00	SP Steel	5.39		1
9	Hemingway	Bowmont	230.00	230.00	SP Steel	13.01		1
10	Langley Gulch	Galloway Rd	138.00	230.00	SP Steel	14.19		1
11	Galloway Rd	Willis Tap	138.00	230.00	SP Steel	2.09		1
12	Walla Walla	Hurricane	230.00	230.00	H Wood	31.66		1
13	Boise Bench	Midpoint #1	230.00	230.00	S Tower	0.87		1
14	Boise Bench	Midpoint #1	230.00	230.00	H Wood	108.68		1
15	Brownlee	Quartz Jct	230.00	230.00	S Tower	1.51		1
16	Brownlee	Quartz Jct	230.00	230.00	H Wood	41.30		1
17	Brownlee	Boise Bench #1 & #2	230.00	230.00	S Tower	99.76		2
18	Oxbow	Brownlee	230.00	230.00	S Tower	10.40		2
19	Boise Bench	Midpoint #2	230.00	230.00	S Tower	3.49		1
20	Boise Bench	Midpoint #2	230.00	230.00	H Wood	102.17		1
21	Oxbow	Pallette Jct	230.00	230.00	S Tower	20.11		2
22	Pallette Jct	Imnaha	230.00	230.00	H Wood	24.43		2
23	Hells Canyon	Palette Jct	230.00	230.00	S Tower	9.05		2
24	Brownlee	Boise Bench	230.00	230.00	S Tower	102.55		2
25	Boise Bench	Midpoint #3	230.00	230.00	H Wood	106.29		1
26	Palette Jct	Enterprise	230.00	230.00	H Wood	29.62		1
27	Borah	Brady #2	230.00	230.00	S Tower	0.46		1
28	Borah	Brady #2	230.00	230.00	H Wood	3.52		1
29	Borah	Brady #1	230.00	230.00	H Wood	3.87		1
30								
31	Goshen	State Line	161.00	161.00	H Wood	40.93		1
32	Don	Goshen	161.00	161.00	S Tower	2.37		2
33	Don	Goshen	161.00	161.00	H Wood	48.42		2
34	Antelope	Goshen	161.00	161.00	H Wood	5.67		1
35								
36					TOTAL	4,769.03	11.02	203

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/Q4

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
2X954 ACSR	236,152	9,282,426	9,518,578					1
1272 ACSR								2
1272 ACSR	81,701	1,666,354	1,748,055					3
1590 ACSR	624,917	22,467,321	23,092,238					4
1590 ACSR		15,210,561	15,210,561					5
1590 ACSR								6
1590 ACSR								7
1590 ACSR		3,528,033	3,528,033					8
1590 ACSR	1,854,996	9,277,980	11,132,976					9
1590 ACSR	948,166	9,080,890	10,029,056					10
1272 ACSR								11
1272 ACSR		6,191,922	6,191,922					12
715.5 ACSR	385,287	9,806,478	10,191,765					13
715.5 ACSR								14
795 ACSR	53,068	3,447,479	3,500,547					15
795 ACSR								16
VARIOUS	289,934	8,966,987	9,256,921					17
1272 ACSR	14,810	1,237,524	1,252,334					18
715.5 ACSR	227,825	16,105,174	16,332,999					19
VARIOUS								20
1272 ACSR	87,468	3,902,140	3,989,608					21
1272 ACSR	171,081	1,674,451	1,845,532					22
1272 ACSR	44,687	1,252,130	1,296,817					23
954 ACSR	184,817	6,257,154	6,441,971					24
715.5 ACSR	247,857	5,849,559	6,097,416					25
1272 ACSR	84,014	1,904,234	1,988,248					26
1272 ACSR	3,068	541,820	544,888					27
715.5 ACSR								28
1272 ACSR	7,248	421,273	428,521					29
								30
250 COPPER	16,155	424,195	440,350					31
715.5 ACSR	88,204	2,312,904	2,401,108					32
397.5 ACSR								33
397.5 ACSR		784,659	784,659					34
								35
	32,174,968	555,434,671	587,609,639	8,044,636	3,092,363	3,084,849	14,221,848	36

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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	American Falls Power Plant	Adelaide	138.00	138.00	H Wood	11.22		2
2	American Falls Power Plant	Adelaide	138.00	138.00	S P Wood	0.12		2
3	Minidoka Loop	Adelaide	138.00	138.00	S Tower	1.15		2
4	Nampa	Caldwell	138.00	138.00	S P Wood	9.57		2
5	Upper Salmon	Mountain Home Jct	138.00	138.00	H Wood	54.45		1
6	Upper Salmon	Cliff	138.00	138.00	H Wood	30.81		1
7	Eastgate	Russet	138.00	138.00	S P Wood	2.08		1
8	Brady	Fremont	138.00	138.00	S Tower	1.03		2
9	Brady	Fremont	138.00	138.00	H Wood	24.38		2
10	Brady	Fremont	138.00	138.00	S P Wood	24.33		2
11	King	Lower Malad	138.00	138.00	H Wood	84.74		2
12	Emmett Jct	Payette	138.00	138.00	H Wood	66.49		2
13	Mountain Home AFB Tap		138.00	138.00	H Wood	6.20		1
14	Ontario	Quartz	138.00	138.00	H Wood	73.40		1
15	King	American Falls PP	138.00	138.00	S Tower	1.01		2
16	King	American Falls PP	138.00	138.00	H Wood	142.41		1
17	King	American Falls PP	138.00	138.00	S P Wood	3.71		1
18	Duffin	Clawson	138.00	138.00	H Wood	6.22		1
19	American Falls	Brady Tie	138.00	138.00	H Wood	0.33		1
20	Upper Salmon A-B	King	138.00	138.00	H Wood	5.66		1
21	Upper Salmon B	Wells	138.00	138.00	H Wood	125.59		1
22	King	Wood River	138.00	138.00	H Wood	63.99		1
23	Toponis	Pocket	138.00	138.00	S P Wood	9.80		1
24	Boise Bench	Grove	138.00	138.00	S P Wood	10.39		2
25	Quartz	John Day	138.00	138.00	H Wood	67.32		1
26	Sinker Creek Tap		138.00	138.00	H Wood	2.80		1
27	Mora	Cloverdale	138.00	138.00	H Wood	2.51		1
28	Mora	Cloverdale	138.00	138.00	S P Wood	22.28		1
29	Mora	Cloverdale	138.00	138.00	S P Steel	0.96		2
30	Stoddard Jct	Stoddard Sub	138.00	138.00	S P Steel	3.80		1
31	Fossil Gulch Tap		138.00	138.00	H Wood	1.95		1
32	Wood River	Midpoint	138.00	138.00	H Wood	53.08		2
33	Wood River	Midpoint	138.00	138.00	S P Wood	16.69		2
34	Oxbow	McCall	138.00	138.00	H Wood	37.15		1
35	Oxbow	McCall	138.00	138.00	S P Wood	2.32		1
36					TOTAL	4,769.03	11.02	203

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/Q4

TRANSMISSION LINE STATISTICS (Continued)

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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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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.
250 COPPER	26,507	381,162	407,669					1
250 COPPER								2
715.5 ACSR	21,327	249,232	270,559					3
795 AAC	696,535	3,311,830	4,008,365					4
795 ACSR	84,229	4,258,619	4,342,848					5
795 ACSR	43,568	2,767,797	2,811,365					6
795 AAC	270,823	561,561	832,384					7
VARIOUS	564,932	4,137,263	4,702,195					8
VARIOUS								9
VARIOUS								10
VARIOUS	76,823	3,206,705	3,283,528					11
VARIOUS	55,521	2,811,621	2,867,142					12
397.5 ACSR	1,955	6,930	8,885					13
VARIOUS	34,428	5,464,961	5,499,389					14
715.5 ACSR	216,919	9,677,074	9,893,993					15
715.5 ACSR								16
715.5 ACSR								17
4\0	4,191	443,775	447,966					18
954 ACSR		96,921	96,921					19
250 COPPER	2,741	753,925	756,666					20
VARIOUS	28,490	3,221,596	3,250,086					21
VARIOUS	173,683	4,156,121	4,329,804					22
397.5 ACSR								23
VARIOUS	225,602	1,652,772	1,878,374					24
397.5 ACSR	92,173	2,463,550	2,555,723					25
VARIOUS	20	77,199	77,219					26
715.5 ACSR	3,123,380	8,853,560	11,976,940					27
VARIOUS								28
795AAC								29
1272 ACSR								30
250 COPPER	450	187,848	188,298					31
397.5 ACSR	349,712	7,115,557	7,465,269					32
397.5 ACSR								33
397.5 ACSR	141,534	2,679,939	2,821,473					34
397.5 ACSR								35
	32,174,968	555,434,671	587,609,639	8,044,636	3,092,363	3,084,849	14,221,848	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	04/15/2016	End of 2015/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.
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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	Lowell Jct	Nampa	138.00	138.00	S P Wood	7.50		2
2	Hunt	Milner	138.00	138.00	S P Wood	19.40		1
3	Strike	Bruneau Bridge	138.00	138.00	H Wood	13.50		1
4	American Falls	Kramer Sub	138.00	138.00	S P Wood	18.46		2
5	Pingree	Haven	138.00	138.00	S P Wood	11.72		1
6	Midpoint	Twin Falls	138.00	138.00	S P Wood	25.22		2
7	Twin Falls	Russett	138.00	138.00	S P Wood	1.69		1
8	Blackfoot	Aiken	46.00	138.00	S P Wood	6.17		2
9	Peterson	Tendoy	69.00	138.00	H Wood	57.10		1
10	Eastgate Tap	Eastgate	138.00	138.00	S P Wood	6.36		1
11	Kimberly Tap	Kimberly	138.00	138.00	S P Steel	1.84		2
12	Boise Bench	Mora	138.00	138.00	H Wood	13.14		2
13	Bowmont-Caldwell	Simplot Sub	138.00	138.00	S P Wood	0.51		1
14	Gary Lane	Eagle	138.00	138.00	S P Wood	6.65		1
15	Locust Grove	Blackcat Sub	138.00	138.00	S P Steel	9.25	2.98	1
16	Boise Bench	Butler	138.00	138.00	S P Wood	0.14	4.02	1
17	Eagle	Star	138.00	138.00	S P Wood	6.74		1
18	Karcher Sub	Zilog Tap	138.00	138.00	S P Steel	3.60		1
19	Cloverdale - 712	712 - Wye	138.00	138.00	S P Steel	0.43	4.02	1
20	Victory Jct	Victory	138.00	138.00	S P Steel	1.89		1
21	Butler	Wye	138.00	138.00	S P Steel	2.94		1
22	Horseflat	Starkey	138.00	138.00	H Wood	33.97		1
23	Starkey	Mccall	138.00	138.00	S P Steel	2.23		2
24	Starkey	Mccall	138.00	138.00	H Wood	3.80		1
25	Starkey	Mccall	138.00	138.00	S P Steel	1.50		1
26	Starkey	Mccall	138.00	138.00	S P Wood	17.61		1
27	Chestnut	Happy Valley	138.00	138.00	S P Steel	2.78		1
28	Garnet	Ward		138.00				
29	McCall	Lake Fork	138.00	138.00	S P Wood	8.89		1
30	McCall	Lake Fork	138.00	138.00	S Steel	2.90		
31	Caldwell	Willis	138.00	138.00	S P Steel	1.30		1
32	Caldwell	Willis	138.00	138.00	S P Steel	1.59		1
33	Caldwell	Willis	138.00	138.00	S P Wood	0.87		1
34	Valivue Tap		138.00	138.00	S P Steel	0.80		2
35	Bowmont	Happy Valley	138.00	138.00	S P Steel	8.72		1
36					TOTAL	4,769.03	11.02	203

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/Q4

TRANSMISSION LINE STATISTICS (Continued)

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715.5 ACSR	211,131	1,454,879	1,666,010					1
715.5 ACSR	3,324	1,426,231	1,429,555					2
397.5 ACSR	14,927	616,667	631,594					3
715.5 ACSR	13,734	1,077,292	1,091,026					4
397.5 ACSR	18,223	1,281,344	1,299,567					5
VARIOUS	66,256	3,110,194	3,176,450					6
715.5 ACSR	16,790	213,033	229,823					7
715.5 ACSR	13,616	529,756	543,372					8
397.5 ACSR	395,696	3,540,775	3,936,471					9
715.5 ACSR	343,955	2,138,853	2,482,808					10
795 ACSR								11
715.5 ACSR	14,697	811,164	825,861					12
795 AAC		50,319	50,319					13
795 AAC	489,037	2,165,954	2,654,991					14
1272 ACSR	935,810	3,503,157	4,438,967					15
1272 ACSR	34,687	838,605	873,292					16
715.5 ACSR	179,817	2,932,783	3,112,600					17
795 AAC	43,035	434,341	477,376					18
1272 ACSR	140,412	2,577,075	2,717,487					19
1272 ACSR								20
795 ACSR	134,471	1,405,436	1,539,907					21
715.5 ACSR	2,473,833	18,884,762	21,358,595					22
715.5 ACSR								23
715.5 ACSR								24
715.5 ACSR								25
715.5 ACSR								26
1272 ACSR	78,579	2,219,508	2,298,087					27
	40,580		40,580					28
715.5 ACSR	331,539	4,682,879	5,014,418					29
								30
1272 ACSR	272,231	2,141,218	2,413,449					31
795 ACSR								32
795 ACSR								33
795 ACSR		351,497	351,497					34
1272 ACSR	691,728	6,045,286	6,737,014					35
	32,174,968	555,434,671	587,609,639	8,044,636	3,092,363	3,084,849	14,221,848	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	04/15/2016	End of 2015/Q4

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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	Antelope	Scoville	138.00	138.00	H Wood	0.12		1
2	American Falls	Wheelon	138.00	138.00	H Wood	1.05		1
3	Kinport	Don #1	138.00	138.00	S Tower	1.32		2
4	Donn	HOKU	138.00	138.00	S P Steel	2.72		1
5	HOKU	Alamed	138.00	138.00	S P Steel	0.22		2
6	HOKU	Alamed	138.00	138.00	S P Steel	0.23		2
7	HOKU	Alamed	138.00	138.00	S P Steel	2.85		1
8	Rockland Jct	Rockland Wind Farm	138.00	138.00	S P Steel	5.30		1
9	King	Justice	138.00	138.00	S P Wood	0.11		1
10	NorthView Tap		138.00	138.00	S P Wood	6.17		1
11	Twin Falls PP Tap		138.00	138.00	H Wood	0.99		1
12	American Falls PP	Amercian Falls Trans ST	138.00	138.00	S P Steel	0.38		1
13	Lower Salmon	King Tie	138.00	138.00	H Wood	0.11		1
14	C J Strike	Strike Jct	138.00	138.00	S Tower	4.30		2
15	Strike Jct	Mountain Home Jct	138.00	138.00	H Wood	23.42		1
16	Strike Jct	Bowmont		138.00	H Wood	0.05		1
17	Strike Jct	Bowmont	138.00	138.00	S Tower	0.36		1
18	Strike Jct	Bowmont	138.00	138.00	H Wood	68.20		1
19	Lucky Peak	Lucky Peak Jct	138.00	138.00	H Wood	4.48		2
20	Bliss	King	138.00	138.00	H Wood	10.47		1
21	Milner Deadend	Milner PP	138.00	138.00	S P Wood	1.30		1
22	Swan Falls Tap		138.00	138.00	H Wood	1.00		1
23								
24								
25								
26	Hines	BPA (Harney)	115.00	115.00	H Wood	3.35		1
27								
28								
29	69 Kv Lines		69.00	69.00	H Wood	167.03		1
30	69 Kv Lines		69.00	69.00	S P Wood	928.75		1
31								
32								
33	46 Kv Lines		46.00	46.00	S P Wood	408.70		1
34								
35	Total all lines					4,769.03	11.02	203
36					TOTAL	4,769.03	11.02	203

TRANSMISSION LINE STATISTICS (Continued)

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

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
397.5 ACSR		11,121	11,121					1
250 COPPER		96,249	96,249					2
715.5 ACSR	1,174	225,641	226,815					3
1272 ACSR	190	4,594	4,784					4
1272 ACSR								5
795 ACSR								6
795 ACSR								7
795 ACSR		-16,973	-16,973					8
1590 ACSR		60,659	60,659					9
715.5 ACSR		4,177,555	4,177,555					10
250 COPPER	58	63,264	63,322					11
715.5 ACSR		76,560	76,560					12
397.5 ACSR		4,406	4,406					13
715.5 ACSR	1,074	622,115	623,189					14
397.5 ACSR	6,332	2,569,728	2,576,060					15
715.5 ACSR	86,651	2,516,180	2,602,831					16
715.5 ACSR								17
								18
715.5 ACSR	7	279,481	279,488					19
715.5 ACSR	5,620	1,366,840	1,372,460					20
715.5 ACSR	2,814	183,606	186,420					21
397.5 ACSR	17,818	261,512	279,330					22
								23
								24
								25
397.5 ACSR	1,978	63,404	65,382					26
								27
								28
VARIOUS	1,680,630	66,163,470	67,844,100					29
VARIOUS								30
								31
								32
VARIOUS	194,536	18,194,925	18,389,461					33
				8,044,636	3,092,363	3,084,849	14,221,848	34
	32,174,968	555,434,671	587,609,639	8,044,636	3,092,363	3,084,849	14,221,848	35
	32,174,968	555,434,671	587,609,639	8,044,636	3,092,363	3,084,849	14,221,848	36

Schedule Page: 422 Line No.: 1 Column: b
This line is jointly owned with PacifiCorp and Idaho Power owns 73.2% of this 85.4 mile line.

Schedule Page: 422 Line No.: 2 Column: b
This line is jointly owned with Portland General Electric and Idaho Power owns 10.0% of this 17.8 mile line.

Schedule Page: 422 Line No.: 3 Column: b
This line is jointly owned with PacifiCorp and Idaho Power owns 22.0% of this 241.3 mile line.

Schedule Page: 422 Line No.: 4 Column: b
This line is jointly owned with PacifiCorp and Idaho Power owns 37.0% of this 129.3 mile line.

Schedule Page: 422 Line No.: 5 Column: b
This line is jointly owned with PacifiCorp and Idaho Power owns 22.0% of this 241.3 mile line.

Schedule Page: 422 Line No.: 6 Column: b
This line is jointly owned with PacifiCorp and Idaho Power owns 37.0% of this 129.3 mile line.

Schedule Page: 422 Line No.: 8 Column: b
This line is jointly owned with PacifiCorp and Idaho Power owns 29.2% of this 226.6 mile line.

Schedule Page: 422 Line No.: 10 Column: b
This line is jointly owned with PacifiCorp and Idaho Power owns 73.2% of this 27.1 mile line.

Schedule Page: 422 Line No.: 11 Column: b
This line is jointly owned with PacifiCorp and Idaho Power owns 29.2% of this approximately 193 mile line.

Schedule Page: 422 Line No.: 12 Column: b
This line is jointly owned with PacifiCorp and Idaho Power owns 29.2% of this 41.2 mile line.

Schedule Page: 422 Line No.: 13 Column: b
This line is jointly owned with PacifiCorp and Idaho Power owns 29.2% of this approximately 193 mile line.

Schedule Page: 422 Line No.: 14 Column: b
This line is jointly owned with PacifiCorp and Idaho Power owns 29.2% of this 47.3 mile line.

Schedule Page: 422 Line No.: 15 Column: b
This line is jointly owned with PacifiCorp and Idaho Power owns 18.3% of this 40.9 mile line.

Schedule Page: 422 Line No.: 16 Column: b
This line is jointly owned with PacifiCorp and Idaho Power owns 64.4% of this 79.5 mile line.

Schedule Page: 422 Line No.: 17 Column: b
This line is jointly owned with PacifiCorp and Idaho Power owns 64.4% of this 77.9 mile line.

Schedule Page: 422 Line No.: 18 Column: b
This line is jointly owned with PacifiCorp and Idaho Power owns 64.4% of this 0.9 mile line.

Schedule Page: 422 Line No.: 34 Column: b
This line is jointly owned with Portland General Electric and Idaho Power owns 10.0% of this 16.7 mile line.

Schedule Page: 422.1 Line No.: 12 Column: b
This line is jointly owned with PacifiCorp and Idaho Power owns 40.8% of this 77.6 mile line.

Schedule Page: 422.1 Line No.: 31 Column: b

This line is jointly owned with PacifiCorp. Idaho Power owns 37.8% of Goshen- Jefferson 28.9 mile segment, 37.8% of the Jefferson- Big Grassy 20.8 mile segment and 100% of the Big Grassy- State Line 40.9 mile segment.

Schedule Page: 422.1 Line No.: 34 Column: b

This line is jointly owned with PacifiCorp and Idaho Power owns 21.9% of this 25.8 mile line.

Schedule Page: 422.4 Line No.: 1 Column: b

This line is jointly owned with PacifiCorp and Idaho Power owns 11.5% of this 1 mile line.

Schedule Page: 422.4 Line No.: 2 Column: b

This line is jointly owned with PacifiCorp and Idaho Power owns 7.2% of this 29.1 mile line.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/Q4

TRANSMISSION LINES ADDED DURING YEAR

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

Line No.	LINE DESIGNATION From (a)	LINE DESIGNATION To (b)	Line Length in Miles (c)	SUPPORTING STRUCTURE Type (d)	SUPPORTING STRUCTURE Average Number per Miles (e)	CIRCUITS PER STRUCTURE Present (f)	CIRCUITS PER STRUCTURE Ultimate (g)
1	Toponis	Pocket	9.80	S P Wood	17.76	1	1
2	NorthView Tap		6.17	S P Wood	16.70	1	1
3	Antelope	Scoville	0.12	H Wood	10.00	1	1
4	American Falls	Wheelon	1.05	H Wood	8.66	1	1
5							
6	Antelope	Goshen	5.67	H Wood	7.13	1	1
7							
8	Walla Walla	Hurricane	31.66	H Wood	4.84	1	1
9							
10	Goshen	Kinport	7.49	Latice	4.56	1	1
11							
12	Summer Lake	Hemingway	53.09	Latice	4.50	1	1
13	Hemingway	Midpoint	47.83	Latice	4.50	1	1
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		162.88		78.65	9	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	04/15/2016	End of 2015/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

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

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

CONDUCTORS			Voltage KV (Operating)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)	(k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
397	ACSR	TVS	138						1
715	ACSR	TVS-HL	138	138,062	2,021,538	2,017,955		4,177,555	2
397	ACSR	Horizonal	138		182	10,939		11,121	3
250	Copper	Horizonal	138		73,562	22,687		96,249	4
									5
397	ACSR	Horizonal	161		667,466	117,193		784,659	6
									7
1272	ACSR	Horizonal	230		4,384,658	1,807,264		6,191,922	8
									9
Double1272	ACSR	Delta	345		232,927	281,797		514,724	10
									11
Double1272	ACSR	Horizonal	500		10,989,610	7,002,272		17,991,882	12
Triple1273	ACSR	Horizonal	500		9,991,982	6,366,612		16,358,594	13
									14
									15
									16
									17
									18
									19
									20
									21
									22
									23
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									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
				138,062	28,361,925	17,626,719		46,126,706	44

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Schedule Page: 424 Line No.: 3 Column: b

This line is jointly owned with PacifiCorp and Idaho Power owns 11.5% of this 1 mile line.

Schedule Page: 424 Line No.: 4 Column: b

This line is jointly owned with PacifiCorp and Idaho Power owns 7.2% of this 29.1 mile line.

Schedule Page: 424 Line No.: 6 Column: b

This line is jointly owned with PacifiCorp and Idaho Power owns 21.9% of this 25.8 mile line.

Schedule Page: 424 Line No.: 8 Column: b

This line is jointly owned with PacifiCorp and Idaho Power owns 40.8% of this 77.6 mile line.

Schedule Page: 424 Line No.: 10 Column: b

This line is jointly owned with PacifiCorp and Idaho Power owns 18.3% of this 40.9 mile line.

Schedule Page: 424 Line No.: 12 Column: b

This line is jointly owned with PacifiCorp and Idaho Power owns 22.0% of this 241.3 mile line.

Schedule Page: 424 Line No.: 13 Column: b

This line is jointly owned with PacifiCorp and Idaho Power owns 37.0% of this 129.3 mile line.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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	**Antelope**	transmission	230.00	161.00	
8	Artesian	distribution	46.00	13.00	
9	Bannock Creek	distribution	46.00	13.00	
10	Bennett Mountain Power Plant- attended	transmission	230.00	18.00	
11	Bennett Mountain Power Plant- attended	distribution	18.00	4.16	
12	Bethel Court	distribution	138.00	13.00	
13	**Big Grassy**	transmission	161.00		
14	Black Cat	distribution	138.00	13.09	
15	Blackfoot	distribution	46.00	13.00	
16	Blackfoot	transmission	161.00	46.00	12.47
17	Blackfoot	distribution	161.00	138.00	12.98
18	Bliss - attended	transmission	138.00	13.80	
19	Blue Gulch	distribution	138.00	35.00	
20	Boise Bench - attended	transmission	230.00	138.00	13.20
21	Boise Bench - attended	distribution	138.00	35.00	
22	Boise Bench - attended	transmission	138.00	69.00	12.98
23	Boise Bench - attended	transmission	230.00	138.00	13.80
24	Boise	distribution	138.00	13.00	
25	**Borah**	transmission	345.00	230.00	13.80
26	Bowmont	distribution	69.00	46.00	6.90
27	Bowmont	distribution	138.00	35.00	
28	Bowmont	transmission	138.00	69.00	12.98
29	Bowmont	transmission	138.00	69.00	12.47
30	Bowmont	transmission	230.00	138.00	13.80
31	Brady	transmission	230.00	138.00	13.80
32	Brady	transmission	138.00	46.00	12.47
33	Brady	distribution	46.00	13.00	
34	Brownlee - attended	transmission	230.00	13.80	
35	Bruneau Bridge	distribution	138.00	35.00	
36	Bruneau Bridge	distribution	138.00	36.20	
37	Buckhorn	distribution	69.00	35.00	
38	Bucyrus	distribution	46.00	7.20	
39	Buhl	distribution	46.00	13.00	
40	Burley Rural	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	04/15/2016	End of 2015/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
300	2					1
20	2					2
15	1					3
18	1					4
72	1					5
25	1					6
224	1					7
10	1					8
10	1					9
135	1					10
5	1					11
15	1					12
						13
24	1					14
30	2					15
50	3	1				16
80	1					17
69	3					18
15	1					19
254	2					20
42	2					21
75	3					22
240	2					23
67	3					24
450	3	1				25
8	3					26
18	1					27
25	1					28
25	1					29
360	2					30
312	3					31
		1				32
		4				33
721	5	1				34
18	1					35
24	1					36
20	1					37
6	1	1				38
10	1	1				39
12	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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	Butler	distribution	138.00	13.09	
2	Caldwell	distribution	138.00	13.00	
3	Caldwell	transmission	230.00	138.00	
4	Caldwell	distribution	138.00	13.09	
5	Caldwell	transmission	138.00	69.00	12.47
6	Caldwell	transmission	230.00	138.00	12.47
7	Caldwell	distribution	13.00	4.16	
8	Canyon Creek	distribution	138.00	35.00	
9	Canyon Creek	transmission	138.00	69.00	12.98
10	Cascade Power Plant - attended	transmission	69.00	4.60	
11	Cascade	distribution	69.00	13.10	
12	Cascade	distribution	25.00		
13	Chestnut	distribution	138.00	13.00	
14	Clear Lake - attended	transmission	46.00	2.40	
15	Cliff	transmission	138.00	46.00	12.50
16	Cliff	transmission	138.00	46.00	12.95
17	Cloverdale	distribution	138.00	13.00	
18	Dale	distribution	46.00	4.60	
19	Dale	distribution	46.00	13.00	
20	Dale	distribution	69.00	13.00	
21	Dale	distribution	138.00	36.20	
22	Dale	transmission	138.00	46.00	12.47
23	Danskin- attended	transmission	230.00	18.00	
24	Danskin- attended	transmission	230.00	138.00	13.80
25	Danskin- attended	distribution	18.00	4.16	
26	Danskin- attended	transmission	138.00	12.00	
27	Danskin- attended	distribution	35.00	13.80	
28	Don	distribution	138.00	7.60	
29	Don	distribution	138.00	13.20	
30	Don	distribution	138.00	13.00	
31	Don	distribution	14.00		
32	DRAM	distribution	138.00	13.09	
33	DRAM	transmission	230.00	138.00	13.80
34	DRAM	distribution	138.00	12.47	
35	Duffin	distribution	138.00	35.00	
36	Eagle	distribution	138.00	13.09	
37	Eastgate	distribution	138.00		
38	Eastgate	distribution	138.00	13.00	
39	Eckert	distribution	138.00	36.20	
40	Eden	distribution	138.00	36.20	

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.
48	2					1
15	1					2
120	1					3
24	1					4
75	3					5
120	1					6
		1				7
15	1					8
15	1					9
12	1					10
15	2					11
4	1					12
48	2					13
4	1					14
12	2	1				15
4	1					16
48	2					17
		1				18
		6				19
		1				20
27	1					21
25	1					22
140	1					23
180	1					24
6	1					25
96	2					26
5	1					27
		1				28
108	6	3				29
26	1	1				30
80	6					31
118	7					32
160	2					33
17	1					34
36	2					35
38	2					36
24	1					37
18	1					38
18	1					39
24	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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	Eden	transmission	138.00	46.00	12.98
2	Elkhorn	distribution	138.00	12.47	
3	Elkhorn	distribution	138.00	13.00	
4	Elmore	distribution	138.00	35.00	
5	Elmore	transmission	138.00	69.00	12.50
6	Elmore	transmission	138.00	69.00	12.98
7	Emmett	distribution	138.00		
8	Emmett	transmission	138.00	69.00	12.47
9	Falls	distribution	46.00	13.00	
10	Falls	distribution	46.00		
11	Filer	distribution	46.00	13.00	
12	Flat Top	distribution	46.00	13.00	
13	Flying H	distribution	69.00	2.40	
14	Fort Hall	distribution	46.00	13.00	
15	Fossil Gulch	distribution	138.00	35.00	
16	Fremont	transmission	138.00	46.00	12.50
17	Gary	distribution	138.00	13.09	
18	Gary	distribution	138.00	13.00	
19	Gem	distribution	69.00	13.00	
20	Gem	distribution	69.00		
21	Gooding Rural	distribution	46.00	13.00	
22	Golden Valley	distribution	69.00	13.00	
23	Goshen	transmission	345.00	161.00	
24	Gowen Substation	distribution	138.00	35.00	
25	Grindstone	distribution	35.00		
26	Grove	distribution	138.00	13.09	
27	Grove	distribution	138.00	13.00	
28	Hagerman	distribution	46.00	13.00	
29	Hagerman	distribution	69.00	13.00	
30	Hailey	distribution	138.00	13.00	
31	Happy Valley	distribution	138.00	13.09	
32	Haven	distribution	138.00	35.00	
33	Haven	transmission	138.00	46.00	
34	Hemingway	transmission	500.00	230.00	34.50
35	Hewlett Packard	distribution	138.00	13.00	
36	Hidden Springs	distribution	138.00	13.00	
37	Highland	distribution	138.00	13.00	
38	Hill	distribution	138.00	13.00	
39	Hillsdale	distribution	138.00		
40	Hoku	distribution	138.00	13.80	

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
15	1					1
8	1					2
8	1					3
17	1					4
15	1					5
15	1					6
24	1					7
25	1					8
8	1					9
10	1					10
10	1					11
13	2					12
15	2					13
10	1	1				14
15	1					15
50	3	1				16
20	1					17
17	1					18
8	1					19
10	1					20
15	2					21
10	1	1				22
896	2					23
24	1					24
5	2					25
48	2					26
24	1					27
10	1					28
5	1					29
20	1					30
18	1					31
12	1					32
25	1					33
600	3	1				34
20	1					35
8	1					36
18	1					37
39	2					38
24	1					39
		2				40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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	Homedale	distribution	69.00	13.00	
2	Horse Flat	transmission	230.00	138.00	13.80
3	Horseshoe Bend	distribution	35.00		
4	Horseshoe Bend	distribution	69.00	36.20	
5	Horseshoe Bend	distribution	69.00	25.00	
6	Huston	distribution	69.00	13.00	
7	Hulen	distribution	46.00	13.00	
8	Hunt	transmission	230.00	138.00	13.80
9	Hydra	distribution	138.00	36.20	
10	Island	distribution	69.00	13.00	
11	Jefferson	transmission	161.00	161.00	
12	Jerome	distribution	138.00	13.00	
13	Jerome	distribution	138.00	13.09	
14	Julion Clawson	distribution	138.00	35.00	
15	Joplin	distribution	138.00	13.00	
16	Joplin	distribution	138.00	35.00	
17	Justice	transmission	230.00	138.00	13.80
18	Karcher	distribution	138.00	13.00	
19	Kenyon	distribution	69.00	13.00	
20	Ketchum	distribution	138.00	13.00	
21	Kimberly	distribution	138.00	13.00	
22	Kinport	transmission	161.00	46.00	13.20
23	Kinport	transmission	230.00	138.00	12.47
24	Kinport	transmission	230.00	138.00	13.80
25	Kinport	transmission	345.00	230.00	13.80
26	Kramer	distribution	138.00	35.00	
27	Kramer	distribution	138.00	36.20	
28	Kuna	distribution	138.00	13.00	
29	Lake	distribution	69.00	13.00	
30	Lake Fork	distribution	138.00	36.20	
31	Lake Fork	transmission	138.00	69.00	12.50
32	Lamb	distribution	138.00	13.00	
33	Langley Gulch- attended	transmission	230.00	138.00	13.80
34	Langley Gulch- attended	transmission	230.00		
35	Langley Gulch- attended	distribution		4.16	
36	Langley Gulch- attended	distribution	13.00	4.16	
37	Langley Gulch- attended	transmission	230.00	150.00	
38	Lansing	distribution	69.00	13.00	
39	Lincoln	distribution	138.00	13.09	
40	Linden	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	04/15/2016	End of 2015/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.
22	2					1
100	1					2
5	1					3
12	1					4
5	1					5
10	1					6
10	1					7
300	3					8
48	2					9
12	1					10
112	1					11
20	1					12
20	1					13
30	2					14
15	1					15
18	1					16
180	1					17
12	1					18
20	2					19
42	2					20
27	1	1				21
		7				22
180	1					23
180	1					24
600	3	1				25
12	1					26
18	1					27
15	1					28
10	1					29
18	1					30
15	1					31
18	1					32
180	1					33
246	2					34
12	1					35
12	1					36
		1				37
12	1					38
10	1					39
33	2					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	Locust	distribution	138.00	36.20	
2	Locust	transmission	230.00	138.00	13.80
3	Lower Malad - attended	transmission	138.00	7.20	
4	Lower Salmon - attended	transmission	138.00	13.80	
5	Map Rock	distribution	69.00	13.00	
6	McCall	distribution	13.00	13.09	
7	McCall	distribution	138.00	36.20	
8	Meridian	distribution	138.00	13.00	
9	Micron	distribution	138.00	13.09	
10	Micron	distribution	138.00	13.00	
11	Midpoint	transmission	230.00	138.00	13.80
12	Midpoint	transmission	345.00	230.00	13.80
13	Midpoint	transmission	500.00	345.00	
14	Midrose	distribution	138.00	13.09	
15	Milner	transmission	138.00	69.00	12.47
16	Milner	distribution	69.00	46.00	6.90
17	Milner	distribution	138.00	35.00	
18	Milner PP - attended	transmission	138.00	13.80	
19	Moonstone	distribution	138.00	35.00	
20	Mora	distribution	138.00	35.00	
21	Mora	distribution	138.00	36.20	
22	Moreland	distribution	35.00	13.00	
23	Moreland	distribution	46.00	13.00	
24	Moreland	distribution	46.00	35.00	12.47
25	Mountain Home	distribution	69.00	13.00	
26	Mountain Home Air Force Base	distribution	69.00	13.00	
27	Mountain Home Air Force Base	distribution	138.00	13.00	
28	Nampa	transmission	230.00	138.00	13.80
29	Nampa	distribution	138.00	13.00	
30	New Meadows	distribution	138.00	36.20	
31	New Plymouth	distribution	69.00	13.00	
32	Notch Butte	distribution	138.00	13.09	
33	Orchard	distribution	69.00	36.20	
34	Orchard	distribution	69.00	35.00	12.47
35	Parma	distribution	69.00	13.00	
36	Parma	distribution	69.00	35.00	
37	Paul	distribution	138.00	35.00	
38	Payette	distribution	138.00	13.00	
39	Pingree	transmission	138.00	46.00	12.50
40	Pingree	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) 04/15/2016	Year/Period of Report End of 2015/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Number of Units (j)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Total Capacity (In MVa) (k)	Line No.
72	3					1
360	2					2
16	1					3
70	4					4
10	1					5
12	1					6
18	1					7
36	2					8
24	2					9
24	2					10
120	1					11
840	2	1				12
750	3					13
24	1					14
75	3	1				15
8	3	1				16
29	2					17
36	1					18
12	1					19
15	1					20
24	1					21
6	1					22
8	1					23
6	3	1				24
15	1					25
		1				26
18	1					27
180	1					28
50	3					29
12	1					30
10	1					31
10	1					32
6	1					33
10	3					34
10	1					35
12	1					36
36	2					37
23	3					38
50	3					39
22	2					40

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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	Pleasant Valley	distribution	138.00	35.00	
2	Pocatello	distribution	46.00	13.00	
3	Pocket	distribution	138.00	36.20	
4	Poleline	distribution	138.00	13.09	
5	Populus	transmission	345.00		
6	Portneuf	distribution	138.00	35.00	
7	Portneuf	distribution	46.00	35.00	
8	Rockford	distribution	46.00	13.00	
9	Russett	distribution	138.00	13.00	
10	Sailor Creek	distribution	138.00	2.40	
11	Sailor Creek	distribution	138.00	35.00	
12	Salmon	distribution	69.00	13.00	
13	Salmon	distribution	69.00	34.50	12.47
14	Salmon	distribution	69.00		12.47
15	Salmon	transmission	13.00	2.40	
16	Shoshone	distribution	46.00	13.00	
17	Shoshone	distribution	46.00	7.20	
18	Shoshone Falls - attended	transmission	46.00	2.30	
19	Shoshone Falls - attended	transmission	46.00	6.60	
20	Silver	distribution	138.00	35.00	
21	Simplot	distribution	138.00	13.00	
22	Sinker Creek	distribution	138.00	35.00	
23	Siphon	distribution	138.00	35.00	
24	South Park	distribution	46.00	13.00	
25	Star	distribution	138.00	13.09	
26	Starkey	transmission	138.00	69.00	12.47
27	State	distribution	69.00	13.00	
28	Stoddard	distribution	138.00	13.00	
29	Strike Power Plant - attended	transmission	138.00	13.80	
30	Sugar	distribution	138.00	35.00	
31	Swan Falls - attended	transmission	138.00	6.90	
32	Taber	distribution	46.00	13.00	
33	Ten Mile	distribution	138.00	13.09	
34	Terry	distribution	138.00	13.09	
35	Terry	distribution	138.00	13.00	
36	Thousand Springs - attended	transmission	46.00	7.20	
37	Thousand Springs - attended	transmission	7.00	2.40	
38	Three Mile Knoll	transmission	345.00		
39	Toponis	distribution	138.00	33.00	
40	Twin Falls	distribution	138.00	13.09	

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

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

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report End of 2015/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	Twin Falls	transmission	138.00	46.00	12.98
2	Twin Falls PP - attended	transmission	138.00	7.20	
3	Twin Falls PP - attended	transmission	138.00	13.20	
4	Upper Malad - attended	transmission	45.00	7.20	
5	Upper Salmon- attended	transmission	138.00	7.20	
6	Ustick	distribution	138.00	13.00	
7	Vallivue	distribution	138.00	13.09	
8	Victory	distribution	138.00	13.00	
9	Victory	distribution	138.00	13.09	
10	Ware	distribution	69.00	13.00	
11	Weiser	distribution	69.00	13.00	
12	Weiser	transmission	138.00	69.00	12.47
13	Wilder	distribution	69.00	13.00	
14	Willis	distribution	138.00	13.09	
15	Wye	distribution	138.00	13.00	
16	Wye	distribution	138.00	13.09	
17	Zilog	distribution	138.00	13.09	
18					
19					
20	The above are all State of Idaho				
21					
22	Montana:				
23	Peterson	transmission	230.00	69.00	13.20
24					
25	Nevada:				
26	Valmy - attended	transmission	345.00	125.00	24.90
27	Valmy - attended	transmission	345.00	125.00	24.90
28	Valmy - attended	transmission	120.00	24.90	7.20
29	Valmy - attended	transmission	345.00		
30	Valmy - attended	transmission	345.00		
31	Valmy - attended	transmission	345.00		
32	Valmy - attended	transmission	345.00		
33	Valmy - attended	transmission	345.00		
34	Wells	transmission	138.00	69.00	13.00
35					
36	Oregon:				
37	Boardman - attended	transmission	500.00	24.00	
38	Boardman - attended	transmission	230.00	7.20	
39	Boardman - attended	transmission	24.00	7.20	
40	Burns	transmission	500.00		

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	04/15/2016	End of 2015/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.
33	2					1
9	1					2
72	1					3
8	1					4
36	4					5
44	2					6
18	1					7
24	1					8
18	1					9
12	1	1				10
20	2					11
25	1					12
10	1					13
18	1					14
36	2					15
20	1					16
24	1					17
						18
						19
						20
						21
						22
24	3	1				23
						24
						25
	1					26
	1					27
	1					28
			Line Reactor	1	48	29
			Line Reactor	1	35	30
			Line Reactor	1	35	31
			Line Reactor	1	35	32
			Line Reactor	1	35	33
20	3	1				34
						35
						36
685	3					37
55	1					38
55	1					39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/15/2016	End of 2015/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	Cairo	distribution	69.00	13.00	
2	Hells Canyon - attended	transmission	230.00	13.80	
3	Hells Canyon - attended	distribution	69.00	0.50	
4	Hines	transmission	138.00	115.00	12.47
5	Hurricane	transmission	230.00		
6	Malheur Butte	distribution	69.00	34.50	
7	Nyssa	distribution	69.00	13.00	
8	Ontario	distribution	138.00	13.00	
9	Ontario	transmission	138.00	69.00	12.47
10	Ontario	transmission	230.00	138.00	13.80
11	Ontario	transmission	138.00	69.00	12.98
12	Ontario	transmission	138.00	69.00	13.09
13	Ore-Ida	distribution	69.00	13.00	
14	Oxbow - attended	transmission	138.00	69.00	13.00
15	Oxbow - attended	transmission	230.00	13.80	
16	Oxbow - attended	transmission	230.00	138.00	13.80
17	Quartz	transmission	138.00	69.00	12.50
18	Quartz	transmission	230.00	138.00	12.98
19	Quartz	transmission	138.00	69.00	12.98
20	Summer Lake	transmission	500.00		
21	Vale	distribution	69.00	13.00	
22					
23	Washington:				
24	Walla Walla	transmission	230.00		
25					
26	Wyoming:				
27	Jim Bridger - attended	transmission	345.00	22.00	34.50
28					
29					
30					
31					
32					
33	Transformers-distribution substations under 10,000				
34	KVA 83 unattended.				
35					
36					
37					
38					
39					
40					

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
12	1					1
500	3	1				2
1	1					3
40	1					4
						5
8	3	1				6
20	2					7
38	2					8
25	1	1				9
240	2					10
50	2					11
		1				12
15	1					13
10	3	1				14
244	2					15
100	1					16
15	1					17
100	3	1				18
15	1					19
						20
10	1					21
						22
						23
						24
						25
						26
2244	4					27
						28
						29
						30
						31
						32
						33
329						34
						35
						36
						37
						38
						39
						40

Name of Respondent Idaho Power Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/15/2016	Year/Period of Report 2015/Q4

FOOTNOTE DATA

Schedule Page: 426 Line No.: 1 Column: a
PacifiCorp has an ownership interest in certain high-voltage transmission related and interconnection equipment located at Idaho Power's Adelaide station. Ownership interest varies by terminal.

Schedule Page: 426 Line No.: 7 Column: a
Idaho Power has an ownership interest in certain high-voltage transmission related and interconnection equipment located at PacifiCorp's Antelope station. Ownership interest varies by terminal.

Schedule Page: 426 Line No.: 13 Column: a
Idaho Power has an ownership interest in certain high-voltage transmission related and interconnection equipment located at PacifiCorp's Big Grassy station. Ownership interest varies by terminal.

Schedule Page: 426 Line No.: 25 Column: a
PacifiCorp has an ownership interest in certain high-voltage transmission related and interconnection equipment located at Idaho Power's Borah station. Ownership interest varies by terminal.

Schedule Page: 426.2 Line No.: 23 Column: a
Idaho Power has an ownership interest in certain high-voltage transmission related and interconnection equipment located at PacifiCorp's Goshen station. Ownership interest varies by terminal.

Schedule Page: 426.2 Line No.: 34 Column: a
PacifiCorp has an ownership interest in certain high-voltage transmission related and interconnection equipment located at Idaho Power's Hemingway station. Ownership interest varies by terminal.

Schedule Page: 426.3 Line No.: 11 Column: a
Idaho Power has an ownership interest in certain high-voltage transmission related and interconnection equipment located at PacifiCorp's Jefferson station. Ownership interest varies by terminal.

Schedule Page: 426.3 Line No.: 25 Column: a
PacifiCorp has an ownership interest in certain high-voltage transmission related and interconnection equipment located at Idaho Power's Kinport station. Ownership interest varies by terminal.

Schedule Page: 426.4 Line No.: 13 Column: a
PacifiCorp has an ownership interest in certain high-voltage transmission related and interconnection equipment located at Idaho Power's Midpoint station. Ownership interest varies by terminal.

Schedule Page: 426.5 Line No.: 5 Column: a
Idaho Power has an ownership interest in certain high-voltage transmission related and interconnection equipment located at PacifiCorp's Populus station. Ownership interest varies by terminal.

Schedule Page: 426.5 Line No.: 38 Column: a
Idaho Power has an ownership interest in certain high-voltage transmission related and interconnection equipment located at PacifiCorp's Three Mile Knoll station. Ownership interest varies by terminal.

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.: 27 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.: 28 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.: 29 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 Sierra Pacific Power Company, d/b/a NV Energy. Idaho Power has a 50% share of ownership.

Schedule Page: 426.6 Line No.: 31 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.: 32 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.: 33 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.: 37 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.: 38 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.: 39 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.: 40 Column: a
Idaho Power has a 22% ownership interest in certain high-voltage transmission related and interconnection equipment located at PacifiCorp's Burns station.

Schedule Page: 426.7 Line No.: 5 Column: a
Idaho Power has an ownership interest in certain high-voltage transmission related and interconnection equipment located at PacifiCorp's Hurricane station. Ownership interest varies by terminal.

Schedule Page: 426.7 Line No.: 20 Column: a
Idaho Power has an ownership interest in certain high-voltage transmission related and interconnection equipment located at PacifiCorp's Summer Lake station. Ownership interest varies by terminal.

Schedule Page: 426.7 Line No.: 24 Column: a
Idaho Power has an ownership interest in certain high-voltage transmission related and interconnection equipment located at PacifiCorp's Walla Walla station. Ownership interest varies by terminal.

Schedule Page: 426.7 Line No.: 27 Column: a
Jointly owned with PacificCorp. Idaho Power has a 33.3% share of ownership.

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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) 04/15/2016	Year/Period of Report End of 2015/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	517,693
22			922000	60,452
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
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39				
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41				
42				

ANNUAL REPORT
OREGON SUPPLEMENT TO FERC FORM 1

for
MULTI-STATE ELECTRIC COMPANIES

INDEX

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STATE OF OREGON STATEMENT OF OPERATING INCOME FOR THE YEAR

Line No.	Account (a)	(Ref.) Page No. (b)	ELECTRIC UTILITY Current Year (c)	Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)..	2	$ 57,999,613	$ 58,072,640
3	Operating Expenses			
4	Operation Expenses (401)...	8-11	35,936,127	35,670,311
5	Maintenance Expenses (402)..	8-11	3,414,243	3,330,826
6	Depreciation Expense (403)...	12	5,548,792	5,440,231
7	Amort. & Depl. of Utility Plant (404-405)................................	12	294,146	305,974
8	Amort. of Utility Plant Acq. Adj. (406)......................................	12	-	-
9	Amort. of Property Losses, Unrecovered Plant and Regulatory Study Costs (407-411)	12	(4,003)	(7,943)
10	Accretion Expense (411)...	12	10,130	13,462
11	Amort. of Conversion Expenses (407)....................................	12		
12	Taxes Other Than Income Taxes (408.1)...............................	13	2,241,676	2,178,512
13	Regulatory Debits/Credits...	14	82,611	73,651
14	Income Taxes - Federal (409.1)..	14	(27,167)	(358,505)
15	- Other (409.1)..	15	160,543	284,353
16	Provision for Deferred Inc. Taxes (410.1)...............................	16-23	3,331,242	6,432,277
17	(Less) Provision for Deferred Income Taxes - Cr.(411.1).........	16-23	(2,179,880)	(5,661,366)
18	Investment Tax Credit Adj. - Net (411.4).................................	24	20,588	1,774
19	(Less) Gains from Disp. of Utility Plant (411.6).......................			
20	Losses from Disp. of Utility Plant (411.7)................................			
21	TOTAL Utility Operating Expenses (Enter lines 4 thru 20)....		48,829,048	47,703,558
22	Net Utility Operating Income (Total of line 2 less 20).............		$ 9,170,565	$ 10,369,082

ELECTRIC OPERATING REVENUES (Account 400) - STATE OF OREGON

1. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
2. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The average number of customers means the average of twelve figures at the close of each month.
3. If previous year (columns (c), (e) and (g), are not derived from previously reported figures, explain any inconsistencies in a footnote.
4. Commercial and Industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regula used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (Se Account 442 of the Uniform System of Accounts. Expl basis of classification in a footnote).
5. See page 108, Important Changes During Year, for important new territory added and important rate increases or decreases.
6. For lines 2, 4, 5, and 6, see page 304 for amounts relating to unbilled revenue by accounts.
7. Include unmetered sales. Provide details of such sales in a footnote.

Line No.	(a)	OPERATING REVENUES Amount for Current Year (b)	OPERATING REVENUES Amount for Previous Year (c)	MEGAWATT HOURS SOLD Amount for Current Year (d)	MEGAWATT HOURS SOLD Amount for Previous Year (e)	AVG NO OF CUSTOMERS PER MONTH Number for Current Year (f)	AVG NO OF CUSTOMERS PER MONTH Number for Previous Year (g)	Line No.
1	Sales of Electricity							1
2	(440) Residential Sales	$ 17,456,867	$ 18,244,476	173,181	181,003	13,369	13,347	2
3	(442) Commercial and Industrial Sales							3
4	Small (or Commercial) (See Instr. 4) (1)	19,070,245	17,394,273	223,098	202,156	5,299	5,176	4
5	Large (or Industrial) (See Instr. 4) (2)	15,674,164	15,072,302	256,839	246,144	6	6	5
6	(444) Public Street and Highway Lighting	134,231	156,911	910	987	32	32	6
7	(445) Other Sales to Public Authorities							7
8	(446) Sales to Railroads and Railways							8
9	(448) Interdepartmental Sales							9
10	TOTAL Sales to Ultimate Consumers	52,335,507*	50,867,962*	654,029 **	630,290	18,706	18,561	10
11	(447) Sales for Resale - Opportunity Non-Firm	1,409,856	3,423,845	57,245	98,521			11
12	TOTAL Sales of Electricity	53,745,363	54,291,807	711,274	728,811	18,706	18,561	12
13	(Less) (449.1) Provision for Rate Refunds	-	(15,203)					13
14	TOTAL Revenue Net of Provision for Refunds	53,745,363	54,307,010					
15	Other Operating Revenues							
16	(450) Forfeited Discounts							
17	(451) Miscellaneous Service Revenues	83,132	83,536					
18	(453) Sales of Water and Water Power							
19	(454) Rent from Electric Property	1,138,991	1,119,257					
20	(455) Interdepartmental Rents							
21	(456) Other Electric Revenues	3,032,127	2,562,835					
22								
23								
24								
25	TOTAL Other Operating Revenues	4,254,250	3,765,628					
26	TOTAL Electric Operating Revenues	$ 57,999,613	$ 58,072,638					

* Includes $253,387 unbilled revenues.

** Includes 2,044 MWH relating to unbilled revenues.

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

(2) Commercial and Industrial sales - Large - 1,000 KW and over.

STATE OF OREGON SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate Schedule (a)	MWH Sold (b)	Revenue (Thousands) (c)	Average Number of Customers (d)	KWH of Sales per Customer (e)	Revenue (cents) per KWH Sold (f)
1	440 - Residential Sales:					
2	01 - Residential	173,701	$ 17,449,928	13,369	12,993	10.05
3	03 - Residential-Mastered Metered					
4	05 - Residential - TOD					
5	15 - Dusk to Dawn customer Lighting	185	51,887			28.05
6	**Residential - Billed**	**173,886**	**17,501,815**	**13,369**	**13,007**	**10.07**
7	Residential - Unbilled	(705)	55,484			(7.87)
8	Bridger Depr & Boardman Decomm		(100,432)			
9	**Total 440**	**173,181**	**17,456,867**	**13,369**	**12,954**	**10.08**
10						
11	442 - Commercial and Industrial Sales:					
12	07 - General Service	17,565	1,880,310	2,483	7,074	10.71
13	09P - General Service	18,352	1,304,914	6	3,058,583	7.11
14	09S - General Service	112,974	8,949,865	888		
15	09T - General Service	2,526	173,536	1		
16	15 - Dusk to dawn customer lighting	258	58,766			22.78
17	19P - Uniform rate contracts	155,392	9,748,107	5	31,078,400	6.27
18	19S - Uniform rate contracts					
19	19T - Uniform rate contracts	102,028	6,084,926	1		
20	24S - Irrigation and soil drainage pumpin	68,089	6,572,071	1,919	35,482	9.65
21	40 - General Service	6	539	2	3,000	8.98
22	**Commercial & Industrial - Billed**	**477,189**	**34,773,034**	**5,305**	**89,951**	**7.29**
23	Commercial & Industrial - Unbilled	2,749	202,149			7.35
24	Bridger Depr & Boardman Decomm		(231,284)			
25	**Total 442**	**479,938**	**34,743,899**	**5,305**	**90,469**	**7.24**
26						
27						
28	444 - Public Street and Highway Lighting:					
29	40 - General Service					
30	41 - Municipal street lighting	889	136,855	25	35,560	15.39
31	42 - Municipal traffic control signal lightir	21	2,004	7	3,000	9.54
32	**Public Street & Highway lighting billed**	**910**	**138,859**	**32**	**28,438**	**15.26**
33	Public St & Highway lighting-unbilled		(4,246)			
34	Bridger Depr & Boardman Decomm		(382)			
35	**Total 444**	**910**	**134,231**	**32**	**28,438**	**14.75**
36						
37						
38						
39						
40						
41	Total Billed	651,985	52,081,610	18,706	34,854	7.99
42	Total Unbilled Rev. (See Instr. 6)	2,044	253,387			
43	TOTAL	654,029	52,334,997	18,706	34,854	7.99

ALLOCATED SALES FOR RESALE (Account 447) - STATE OF OREGON

1. Report sales during the year to other electric utilities and to cities or other public authorities for distribution to ultimate consumers.

2. Provide in column (a) subheadings and classify sales as to (1) Associated Utilities, (2) Nonassociated Utilities, (3) Municipalities, (4) Cooperatives, and (5) Other Public Authorities. For each sale designate statistical classification in column (b) using the following codes: FP, firm power supplying total system requirements of customer or total requirements at a specific point of delivery; FP(C), firm power supplying total system requirements of customer or total requirements at a specific point of delivery with credit allowed customer for available standby; FP(P), firm power supplementing customer's own generation or other purchases; DP, dump power; O, other. Describe in a footnote the nature of any sales classified as Other Power. Place an "x" in column (c) if sales involves export across a state line. Group together sales coded "x" in column (c) by state (or county) of origin identified in column (e), providing a subtotal for each state (or county) of delivery in columns (L) and (p).

Line No.	Sales To (a)	Stat. Class (b)	Export Across State Lines (c)	FERC Rate Sch. No. (d)	Point of Delivery (State or County) (e)	Station Owner-Ship (f)	MW or MVa of Demand (Specify which): Contract Demand (g)	Average Monthly Maximum Demand (h)	Annual Maximum Demand (i)
1									
2									
3	Various Utilities								
4									
5									
6									
7									
8									
9									
10									
11									
12									
13									
14									
15									
16									
17									
18									
19									
20									
21									
22									
23									
24									
25									
26									
27									
28									
29									

ALLOCATED SALES FOR RESALE (Account 447) (Continued) - STATE OF OREGON

3. Report separately firm, dump, and other power sold to the same utility.

4. If delivery is made at a substation, indicate ownership in column (f), using the following codes: RS, respondent owned or leased; CS, customer owned or leased.

5. If a fixed number of megawatts of maximum demand is specified in the power contract as a basis of billings to the customer, enter this number in column (g). Base the number of megawatts of maximum demand entered in columns (h) and (i) on actual monthly readings. Furnish these figures whether or not they are used in the determination of demand charges. Show in column (j) type of demand reading (i.e., instantaneous, 15, 30, or 60 minutes integrated).

6. For column (l) enter the number of megawatt hours shown on the bills rendered to the purchasers.
7. Explain in a footnote any amounts entered in column (o), such as fuel or other adjustments.
8. If a contract covers several points of delivery and small amounts of electric energy are delivered at each point, such sales may be grouped.

Type of Demand Reading (j)	Voltage at Which Delivered (k)	Megawatt Hours (l)	REVENUE Demand Charges (m)	Energy (n)	Other Charges (o)	Total (p)	Line No.
							1
							2
				1,409,856		$ 1,409,856	3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
							15
							16
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							19
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							21
							22
							23
							24
							25
							26
							27
							28
							29

SALES TO RAILROADS AND RAILWAYS AND INTERDEPARTMENTAL SALES (Accounts 446, 448)

1. Report particulars concerning sales included in Accounts 446 and 448.
2. For Sales to Railroads and Railways, Account 446, give name of railroad or railway in addition to other required information. If contract covers several points of delivery and small amounts of electricity are delivered at each point, such sales may be grouped.
3. For Interdepartmental Sales, Account 448, give name of other department and basis of charge to other department in addition to other required information.
4. Designate associated companies.
5. Provide subheading and total for each account.

Line No.	Item (a)	Point of Delivery (b)	Kilowatt-hours (c)	Revenue (d)	Revenue per KWH (e)
1	None				
2					
3					
4					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

RENT FROM ELECTRIC PROPERTY AND INTERDEPARTMENTAL RENTS (Accounts 454, 455)

1. Report particulars concerning rents received included in Accounts 454 and 455.
2. Minor rents may be grouped by classes.
3. If rents are included which were arrived at under an arrangement for apportioning expenses of a joint facility, whereby the amount included in this account represents profit or return on property, depreciation, and taxes, give particulars and the basis of apportionment of such charges to Account 454 or 455.
4. Designate if lessee is an associated company.
5. Provide a subheading and total for each account.

Line No.	ame of Lessee or Department (a)	Description of Property (b)	Amount of Revenue For Year (c)
21	Various	Substation Equipment Rental	$ 469,054
22			
23	"	Transformer Rentals - Dist	561
24			
25	"	Line Rentals	99,271
26			
27	"	Cogeneration	48,802
28			
29	"	Pole Attachments	115,099
30			
31	"	Facilities Charges	381,186
32			
33	"	Other Rentals	25,018
34			
35	"	Miscellaneous	-
36			
37	"		
38	Total Account 454		$ 1,138,991

ALLOCATED SALES OF WATER AND WATER FOR POWER (Account 453) - OREGON

1. Report below the information called for concerning revenues derived during the year from sales to others of water or water power.
2. In column (c) show the name of the power development of the respondent supplying the water or water power sold.
3. Designate associated companies.

Line No.	Name of Purchaser (a)	Purpose for which Water was Used (b)	Power Plant Development (c)	Amount of Revenue for Year (d)
1	None			
2				
3		TOTAL		

MISCELLANEOUS SERVICE REVENUES AND OTHER ELECTRIC REVENUES (Accounts 451, 456)

1. Report particulars concerning miscellaneous service revenues and other electric revenues derived from electric utility operations during year. Report separately in this schedule the total revenues from operation of fish and wildlife and recreation facilities, regardles of whether such facilities are operated by company or by contract concessionaires. Provide a subheading and total for each account. For account 456, list first revenues realized through Research and Development ventures, see account 456.
2. Designate associated companies.
3. Minor items may be grouped by classes.

Line No.	Name of Company and Description of Service	Amount of Revenue for Year (b)
4	Account 451	
5		
6	Miscellaneous Service Revenues	$ 83,132
7		
8	Account 456	
9		
10	Transmission for Others - Network	$ 341,098
11	Transmission - Point-to-Point and Other	647,447
12	Photovoltaic Station Service	-
13	DSM Rider Funds	2,037,343
14	Sierra Pacific Usage Charge	3,147
15	Antelope	2,786
16	Miscellaneous	306
17		
18		
19		
20	Total Account 456	$ 3,032,127
21		
22		
23		

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
	ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES - OREGON		
	If the amount for previous year is not derived from previously reported figures, explain in footnotes.		
1	(1) POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	$ 52,912	$ 58,670
5	(501) Fuel	5,992,594	6,929,438
6	(502) Steam Expenses	446,940	387,854
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	57,612	70,971
10	(506) Miscellaneous Steam Power Expenses	274,292	409,061
11	(507) Rents	17,750	22,609
12	(509) Allowances		
13	TOTAL Operation (Enter Total of lines 4 thru 12)	6,842,100	7,878,604
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	5,217	11,842
16	(511) Maintenance of Structures	36,075	30,185
17	(512) Maintenance of Boiler Plant	632,714	484,662
18	(513) Maintenance of Electric Plant	247,057	268,218
19	(514) Maintenance of Miscellaneous Steam Plant	284,439	247,447
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	1,205,503	1,042,355
21	TOTAL Power Production Expenses-Steam Power (Enter Total of lines 13 and 20)	8,047,603	8,920,958
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuclear Power (Enter Total of lines 33 and 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	240,006	243,622
45	(536) Water for Power	372,651	311,786
46	(537) Hydraulic Expenses	612,487	600,796
47	(538) Electric Expenses	68,262	65,794
48	(539) Miscellaneous Hydraulic Power Generation Expenses	233,169	244,301
49	(540) Rents	9,666	11,068
50	TOTAL Operation (Enter Total of lines 44 thru 49)	1,536,241	1,477,368

ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued) - OREGON			
If the amount for previous year is not derived from previously reported figures, explain in footnotes.			
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Maintenance Supervision and Engineering	$ 4,944	$ 5,207
54	(542) Maintenance of Structures	46,035	59,124
55	(543) Maintenance of Reservoirs, Dams, and Waterways	23,642	15,611
56	(544) Maintenance of Electric Plant	113,866	98,397
57	(545) Maintenance of Miscellaneous Hydraulic Plant	117,506	108,869
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	305,992	287,208
59	TOTAL Power Production Expenses-Hydraulic Power (Enter Total of lines 50 and 58)	1,842,234	1,764,576
61	Operation		
62	(546) Operation Supervision and Engineering	26,567	34,684
63	(547) Fuel	2,507,960	1,999,727
64	(548) Generation Expenses	198,529	155,723
65	(549) Miscellaneous Other Power Generation Expenses	38,388	38,592
66	(550) Rents	-	-
67	TOTAL Operation (Enter Total of lines 62 thru 66)	2,771,444	2,228,726
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	-	-
70	(552) Maintenance of Structures	14,942	16,112
71	(553) Maintenance of Generating and Electric Plant	3,125	3,764
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	52,186	59,297
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	70,253	79,173
74	TOTAL Power Production Expenses-Other Power (Enter Total of lines 67 and 73)	2,841,698	2,307,899
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	9,919,405	10,516,280
77	(556) System Control and Load Dispatching	100	(53)
78	(557) Other Expenses	2,452,085	2,334,208
79	TOTAL Other Power Supply Expenses (Enter Total of lines 76 thru 78)	12,371,590	12,850,435
80	TOTAL Power Production Expenses (Enter Total of lines 21, 41, 59, 74, and 79)	25,103,124	25,843,868
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	170,284	171,639
84	(561) Load Dispatching	120,729	114,812
85	(562) Station Expenses	108,395	104,957
86	(563) Overhead Line Expenses	39,841	28,595
87	(564) Underground Line Expenses		
88	(565) Transmission of Electricity by Others	286,612	269,830
89	(566) Miscellaneous Transmission Expenses	97	780
90	(567) Rents	126,995	140,275
91	TOTAL Operation (Enter Total of lines 83 thru 90)	852,955	830,890
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	6,465	7,238
94	(569) Maintenance of Structures	38,324	44,256
95	(570) Maintenance of Station Equipment	135,275	158,083
96	(571) Maintenance of Overhead Lines	120,896	136,661
97	(572) Maintenance of Underground Lines		
98	(573) Maintenance of Miscellaneous Transmission Plant	-	68
99	TOTAL Maintenance (Enter Total of lines 93 thru 98)	300,960	346,307
100	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	1,153,915	1,177,196
102	Operation		
103	(580) Operation Supervision and Engineering	186,340	172,579

ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued) - OREGON			
If the amount for previous year is not derived from previously reported figures, explain in footnotes.			
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
104	3. DISTRIBUTION EXPENSES (Continued)		
105	(581) Load Dispatching	$ 147,231	$ 142,656
106	(582) Station Expenses	60,472	40,668
107	(583) Overhead Line Expenses	291,515	230,739
108	(584) Underground Line Expenses	39,148	35,910
109	(585) Street Lighting and Signal System Expenses	4,060	3,503
110	(586) Meter Expenses	163,022	147,962
111	(587) Customer Installations Expenses	59,638	53,885
112	(588) Miscellaneous Distribution Expenses	262,440	247,970
113	(589) Rents	11,385	19,967
114	TOTAL Operation (Enter Total of lines 103 thru 113)	1,225,252	1,095,840
115	Maintenance		
116	(590) Maintenance Supervision and Engineering	462	705
117	(591) Maintenance of Structures	-	-
118	(592) Maintenance of Station Equipment	163,900	136,125
119	(593) Maintenance of Overhead Lines	1,043,477	1,022,270
120	(594) Maintenance of Underground Lines	8,190	8,965
121	(595) Maintenance of Line Transformers	1,383	5,800
122	(596) Maintenance of Street Lighting and Signal Systems	22,475	24,223
123	(597) Maintenance of Meters	26,251	24,593
124	(598) Maintenance of Miscellaneous Distribution Plant	22,027	32,465
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	1,288,164	1,255,147
126	TOTAL Distribution Expenses (Enter Total of lines 114 and 125)	2,513,415	2,350,986
127	4. CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision	17,671	22,068
130	(902) Meter Reading Expenses	78,963	206,108
131	(903) Customer Records and Collection Expenses	555,097	600,300
132	(904) Uncollectible Accounts	191,185	398,936
133	(905) Miscellaneous Customer Accounts Expenses	16	5
134	TOTAL Customer Accounts Expenses (Enter Total of lines 129 thru 133)	842,932	1,227,417
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision	48,872	32,177
138	(908) Customer Assistance Expenses	2,275,477	1,850,917
139	(909) Informational and Instructional Expenses	15,192	13,513
140	(910) Miscellaneous Customer Service and Informational Expenses	44,303	37,606
141	TOTAL Cust. Service and Informational Expenses (Enter Total of lines 137 thru 140)	2,383,844	1,934,213
142	6. SALES EXPENSES		
143	Operation		
144	(911) Supervision		
145	(912) Demonstrating and Selling Expenses	3,639	
146	(913) Advertising Expenses		
147	(916) Miscellaneous Sales Expenses		
148	TOTAL Sales Expenses (Enter Total of lines 144 thru 147)	3,639	
149	7. ADMINISTRATIVE AND GENERAL EXPENSES		
150	Operation		
151	(920) Administrative and General Salaries	3,255,870	3,313,235
152	(921) Office Supplies and Expenses	655,957	789,641
153	(922) Administrative Expenses Transferred-Credit	(1,163,996)	(1,234,364)

ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued) - OREGON			
If the amount for previous year is not derived from previously reported figures, explain in footnotes.			
Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
154	7. ADMINISTRATIVE AND GENERAL EXPENSES (Continued)		
155	(923) Outside Services Employed	$ 364,427	$ 213,073
156	(924) Property Insurance	140,544	145,759
157	(925) Injuries and Damages	296,110	277,374
158	(926) Employee Pensions and Benefits	3,004,798	2,183,514
159	(927) Franchise Requirements	-	-
160	(928) Regulatory Commission Expenses	282,156	215,826
161	(929) Duplicate Charges-Cr.		
162	(930.1) General Advertising Expenses	27,544	20,521
163	(930.2) Miscellaneous General Expenses	242,637	222,233
164	(931) Rents	84	8
165	TOTAL Operation (Enter Total of lines 151 thru 164)	7,106,131	6,146,820
166	Maintenance		
167	(935) Maintenance of General Plant	243,371	320,637
168	TOTAL Administrative and General Expenses (Enter Total of lines 165 thru 167)	7,349,501	6,467,457
169	TOTAL Electric Operation and Maintenance Expenses (Enter Total of lines 80, 100, 126, 134, 141, 148, and 168)	$39,350,370	$ 39,001,137

	SUMMARY OF ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES - OREGON			
Line No.	Functional Classification (a)	Operation (b)	Maintenance (c)	Total (d)
170	Power Production Expenses			
171	Electric Generation:			
172	Steam power	$ 6,842,100	$ 1,205,503	$ 8,047,603
173	Nuclear power			
174	Hydraulic - Conventional	1,536,241	305,992	1,842,234
175	Hydraulic - Pumped Storage			
176	Other power	2,771,444	70,253	2,841,698
	Other Power Supply Expenses	12,371,590	-	12,371,590
177	Total Power Production Expenses	23,521,376	1,581,748	25,103,124
178	Transmission Expenses	852,955	300,960	1,153,915
179	Distribution Expenses	1,225,252	1,288,164	2,513,415
180	Customer Accounts Expenses	842,932	-	842,932
181	Customer Service and Informational Expenses	2,383,844	-	2,383,844
182	Sales Expenses	-	-	-
183	Administrative and General Expenses	7,106,131	243,371	7,349,501
184	Total Electric Operation and Maintenance Expenses	$ 35,932,488	$ 3,414,243	$ 39,346,731

ALLOCATED DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405) - OREGON (Except amortization of acquistion adjustments)					
A. Summary of Depreciation and Amortization Charges					
Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Amortization of Limited-Term Electric Plant (Account 404) (c)	Amortization of Other Electric Plant (Acct. 405) (d)	Total (e)
1	Intangible Plant	$ -	$ 294,146		$ 294,146
2	Steam Production Plant	1,046,875	-		1,046,875
3	Nuclear Production Plant				-
4	Hydraulic Production Plant - Conventional	596,299	-		596,299
5	Hydraulic Production Plant - Pumped Storage				
6	Other Production Plant	701,431	-		701,431
7	Transmission Plant	864,379	-		864,379
8	Distribution Plant	1,879,434	-		1,879,434
9	General Plant	449,210	-		449,210
10	Depreciation on Disallowed Costs	(12,557)	-		(12,557)
11	Boardman ARO Depreciation	23,722			23,722
12	ARO Accretion	10,130			10,130
13	TOTAL	$ 5,558,922	$ 294,146		$ 5,853,068

B. OTHER AMORTIZATION

Describe briefly the nature of each transaction giving rise to amortization included in Account 406, Amortization of Utility Plant Acquisition Adjustments, or Account 407, Amortization of Property Losses. Provide the requested information for each transaction, as well as providing a total for each account.

Nature of Transaction	OPUC Number	Amortization Period	Amount
Account 406			
Amortization of Electric Plant Acquisition Adjustment - Prairie Power			0
Account 411			
411.6			$ -
411.7			-
411.8			(4,003)
			$ (4,003)

ALLOCATED TAXES, OTHER THAN INCOME TAXES (ACCOUNT 408.1) - OREGON

	KIND OF TAX	Amount
1	Federal Taxes:	
2	FICA	$ 652,123
3	FUTA	4,151
4	Less: Payroll Deduction and Loading	(683,436)
5	State Taxes:	
6	Ad Valorem	1,153,231
7	Licenses - Hydro Projects	205
8	Regulatory Commission Fees	206,569
9	Franchise Taxes	824,997
10	State Unemployment Taxes	27,162
11	Hydro Generation KWH Tax	56,674
12	Canada Sales Tax	0
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23	TOTAL (Must agree with page 1, line 12.)	2,241,676

CALCULATION OF CURRENT FEDERAL INCOME TAX EXPENSE - Account 409.1

1. Report amounts used to derive current Federal income tax expense, Account 409.1, for the reporting period. If amounts are shown in thousands, show (000) in the heading for column (b).

2. Show amounts increasing taxable income as positive values and amounts decreasing taxable income as negative.

3. Current tax expense on this schedule must match the amount reported on page 1, line 12 of this report. Separately identify adjustments arising from revisions of prior year accruals.

4. Minor amounts of other additions (subtractions) may be grouped.

Line No.	Particulars (Details) (a)	Amount (b)
1	Electric Operating Revenues	$ 57,999,613
2	Operations and Maintenance Expenses	39,350,370
3	Taxes Other Than Income	2,241,676
4	Regulatory Debits/Credits	82,611
5	State Income (Excise) Tax	191,126
6	Interest	3,864,575
7	Federal Income Tax Depreciation	5,548,792
8	Other Line items to Derive Taxable Income	10,130
9	Amortization of Limited-Term Plant	290,143
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24	Federal Tax Net Income	$ 6,420,189
25		
26		
27	Show Computation of Tax:	
28		
29	Federal Income Tax @ 35%	$ 2,247,066
30	FIN 48 Adjustment	(57,730)
31	Prior Years' Tax Adjustment	179,436
32	Total Federal Income Tax Before Other Adjustments	2,368,772
33		
34	Other Tax Adjustments	
35	Allowance for AFUDC	$ 1,331,639
36	Income Tax Adjustments	(8,177,179)
37	Federal Tax on Other Tax Adj @ 35%	(2,395,939)
38		
39	Total Federal Income Tax	$ (27,167)

CALCULATION OF CURRENT STATE INCOME (EXCISE) TAX EXPENSE - Account 409.1

1. Report amounts used to derive current state income (excise) tax expense, Account 409.1, for the reporting period. If amounts are shown in thousands, show (000) in the heading for column (b).

2. Show amounts increasing taxable income as positive values and amounts decreasing taxable income as negative.

3. Current tax expense on this schedule must match the amount reported on page 1, line 13 of this report. Separately identify adjustments arising from revisions of prior year accruals.

4. Minor amounts of other additions (subtractions) may be grouped.

Line No.	Particulars (Details) (a)	Amount (b)
1	Electric Operating Revenues	$ 57,999,613
2	Operations and Maintenance Expenses	39,350,370
3	Taxes Other Than Income	2,241,676
4	Regulatory Debits/Credits	82,611
5	Interest	3,864,575
6	State Income (Excise) Tax Depreciation	5,548,792
7		
8	Other Line Items to Derive Taxable Income	
9	Amortization of Limited-Term Plant	290,143
	ARO Accretion Expense	10,130
10	Income Tax Adjustments	8,429,868
11	Allowance for AFUDC	(1,331,639)
12	IERCO Taxable Income	(467,548)
13		
14	State Tax Net Income	$ (19,364)
15		
16		
17		
18		
19	Show Computation of Tax:	
20		
21	State Taxes	191,126
22	Add: FIN 48 Adjustment	-
23	Prior Period Adjustment	(30,584)
24		
25		
26	Total Oregon State Tax	$ 160,543

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. In the space provided:
(a) identfy, by amount and classification, significant items for which deferred taxes are being provided.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited (Account 410.1) (c)	Amounts Credited (Account 411.1) (d)
1	Electric			
2	Emission Allowances	$	$ -	$ -
3	Advances for Construction		0	(22,091)
4	Other Operating (See Note 1)		1,030,528	(495,859)
5				
6	Non-Operating			
7				
8				
9	Total Electric	$	$ 1,030,528	$ (517,950)
10	Gas	$	$	$
11				
12				
13	Other			
14	Total Gas	$	$	$
15	Other Non-Electric	$	$	$
16	Total (Account 190)	$	$ 1,030,528	$ (517,950)
17	Classification of TOTALS			
18	Federal Income Tax	$	$	$
19	State Income Tax	$	$	$
20	Local Income Tax	$	$	$
	Note 1:			
	Rate Case Disallowance		0	0
	Executive Deferred Compensation Short-Term		451	0
	Executive Deferred Compensation Long-Term		91	(0)
	SFAS 112 - Post Retirement Benefits		2,916	0
	Non-VEBA Pension and Benefits		0	0
	FAS 123R - Stock Based Compensation		0	(1,128)
	Provision for Rate Refunds		0	0
	Revenue Sharing		67,276	0
	Montana NOL		0	0
	Oregon NOL		0	0
	Federal NOL		0	0
	Valmy Union Pacific Contract		32,679	0
	Deferred Idaho ITC		13,636	(93,489)
	VEBA - Post Retiree Benefits		978	(26,784)
	Bridger Revenue Deferral		0	0
	AFUDC Hells Canyon Relicensing		0	(204,549)
	Reg Liability		68,214	0
	Reg Asset		642,422	0
	Boardman Decommission		0	0
	USBR-American Falls O&M Costs Settlement		0	(4,940)
	Oregon Pension Expense		0	(18,483)
	Incentive Deferral - Profit Sharing not in rates		180,815	(135,627)
	M&E Reserve		21,051	0
	Asset Retirement Obligation (ARO)		0	(10,858)
	Total	$	$ 1,030,528	$ (495,859)

ACCUMULATED DEFERRED INCOME TAXES (Account 190) (Continued)

(b) indicate insignificant amounts under OTHER.
3. Beginning balance may be omitted if not readily available. Report electric utility deferred taxes only.
4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited (Account 410.2)	Amounts Credited (Account 411.2)	Debits		Credits			
		Acct. No.	Amount	Acct. No.	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
$	$		$		$	$	2
							3
							4
							5
7,076	(79,391)						6
							7
							8
$ 7,076	$ (79,391)		$		$	$	9
$	$		$		$	$	10
							11
							12
							13
$	$		$		$	$	14
$ -			$		$	$	15
$ 7,076	$ (79,391)		$		$	$	16
							17
$	$		$		$	$	18
$	$		$		$	$	19
$	$		$		$	$	20
$ -	$ -						

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

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amortizable property.

2. In the space provided furnish explanations, including the following in columnar order:
   (a) State each certification number with a brief description of property.
   (b) Total and amortizable cost of such property.
   (c) Date amortization for tax purposes commenced.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR: Amounts Debited (Account 410.1) (c)	CHANGES DURING YEAR: Amounts Credited (Account 411.1) (d)
1	Accelerated Amortization (Account 281)	NONE		
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities			
5	Other: Accelerated Amortization			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)			
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16	Other (Specify)			
17	TOTAL (Account 281)(Enter Total of 8, 15, and 16)		$ -	$ -
18				
19	Federal Income Tax			
20	State Income Tax			
21	Local Income Tax			

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

(d) "Normal" depreciation rate used in computing the deferred tax.
(e) Tax rate used to originally defer amounts and the tax rate used during the current year to amortize previous deferrals.

3. Beginning balance may be omitted if not readily available. Report electric utility deferred taxes only.

4. Use separate pages as required.

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

ACCUMULATED DEFERRED INCOME TAXES-OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to property not subject to accelerated amortization.

2. In the space provided furnish below explanations,including the following:
State the general method or methods of liberalized depreciation being used (sum-of-year digits, declining balance, etc.,) estimated lives i.e. useful life, guideline life, guideline class life, etc., and classes of plant to

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited (Account 410.1) (c)	Amounts Credited (Account 411.1) (d)
1	Account 282			
2	Electric		$ 1,757,068	$ (762,938)
3	Gas			
4	Other (Define)			
5	TOTAL (Enter Total of lines 2 thru 4)		1,757,068	(762,938)
6	Other (Specify)			
7	FERC Jurisdictional Deferral			
8	Non-Utility Property			
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)		$ 1,757,068	$ (762,938)
10	Classification of TOTAL			
11	Federal Income Tax			
12	State Income Tax			
13	Local Income Tax			
	Line 2:			
	Depr Federal Adj		1,571,669	(760,473)
	Intangible Asset - Labor Deductions		40,403	-
	N Valmy Partnership Capitalized Items		-	(2,435)
	CIAC as Taxable Income		113,920	-
	FERC Juris-S Georgia-Acct 282 Def only		-	-
	Engineering Fees		1,607	(29)
	Software Costs		29,470	-
	Total		1,757,068	(762,938)

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

which each method is being applied and date method was adopted.

3.Beginning balance may be omitted if not readily available. Report electric utility deferred taxes only.

4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited (Account 410.2) (e)	Amounts Credited (Account 411.2) (f)	Debits Acct. No. (g)	Debits Amount (h)	Credits Acct. No. (i)	Credits Amount (j)	Balance at End of Year (k)	Line No.
							1
$ 238,746	$ (238,746)				$ -		2
							3
							4
238,746	(238,746)				0		5
							6
							7
$ -	$ -						8
$ 238,746	$ (238,746)				$ -		9
							10
							11
							12
							13

ACCUMULATED DEFERRED INCOME TAXES-OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. In the space provided below include amounts relating to insignificant items under Other.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited (Account 410.1) (c)	Amounts Credited (Account 411.1) (d)
1	Account 283			
2	Electric (See Note 1)		543,646	(898,993)
3				
4	Total Electric		543,646	(898,993)
5				
6				
7	Other (See Note 2)			
8				
9				
10	Total (Account 283) (Enter Total of lines 4 - 9)		$ 543,646	$ (898,993)
11	Classification of Total:			
12	Federal Income Tax			
13	State Income Tax			
14	Local Income Tax			
	Note 1:			
	Oregon PCAM		0	(28,835)
	FERC Grid West Expense		0	0
	PCA		0	(138,391)
	Conservation Programs		8,880	(10,874)
	Oregon Excess Power Supply Costs		0	(0)
	OATT Revenue Deficiency		0	(3,986)
	Emission Allowances		191	0
	Fixed Cost Adjustment (FCA)		181,863	0
	OPUC Grid West Loans		0	(0)
	Intervenor Funding Orders		0	0
	Bonus Deferral		0	0
	Reorganization Costs		0	0
	Delivery Accruals		690	0
	REC Sales		40,902	(6,272)
	Pension Expense		310,402	0
	LIDAR Surveys Deferral		0	0
	Bennett Mtn Maintenance Deferral		0	0
	Custom Efficiency Incentive Payment		0	0
	Reg Liability		0	(68,214)
	Reg Asset		0	(642,422)
	Langley Revenue Deferral		718	0
	Boardman Decommission		0	0
	PS&I Costs - Coal & CHP Plants - Write Off		0	0
	Total		543,646	(898,993)
	Note 2:			
	Advance Coal Royalties			
	Oregon Non-Operating Property Tax Adj			
	Unrealized Gain/Loss from Rabbi Trust			
	Total			

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

3. Beginning balances may be omitted if not readily available. Report electric utility deferred taxes only.

4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited (Account 410.2) (e)	Amounts Credited (Account 411.2) (f)	Debits Acct. No. (g)	Debits Amount (h)	Credits Acct. No. (i)	Credits Amount (j)	(k)	
							1
0	0						2
							3
-	-		-		-		4
							5
							6
216	(19,164)						7
							8
							9
$ 216	$ (19,164)		$ -		$ -		10
							11
							12
							13
							14

0	0
203	0
13	(13)
0	(19,151)
216	(19,164)

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Explain by footnote any correction adjustments to the account balance shown in column (g). Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year: Account No. (c)	Deferred for Year: Amount (d)	Allocations to Current Year's Income: Account No. (e)	Allocations to Current Year's Income: Amount (f)	Adjustments (g)	Balance at End Year (h)	Average Period of Allocation To Income (i)
1	Electric Utility								
2	3%								
3	4%								
4	7%								
5	10%								
6									
7									
8									
9	TOTAL		411.4	$ 144,550	411.4	$ (123,962)			
10									
11	Other (List separately								
12	and show 3%, 4%, 7%,								
13									
14									
15									
16									
17									
18									
19									
20									
21									
22									
23									
24									
25									
26									
27									
28									
29									

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

Line No.	Item (a)	Total (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Common (g)
1	UTILITY PLANT						
2	In Service						
3	Plant in Service (Classified)	$ 489,042,770	$ 489,042,770				
4	Property Under Capital Leases						
5	Plant Purchased or Sold						
6	Completed Construction not Classified						
7	Experimental Plant Unclassified						
8	TOTAL (Enter Total of lines 3 thru 7)	$ 489,042,770	$ 489,042,770				
9	Leased to Others						
10	Held for Future Use	$ 89,977	$ 89,977				
11	Construction Work in Progress	$ 27,256,349	$ 27,256,349				
12	Acquisition Adjustments						
13	TOTAL Utility Plant (Enter Total of lines 8 thru 12)	$ 516,389,097	$ 516,389,097				
14	Accum. Prov. for Depr., Amort., & Depl	NOT AVAILABLE					
15	Net Utility Plant (Enter Total of line 13 less 14)	$ 516,389,097	$ 516,389,097				
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION						
17	In Service						
18	Depreciation	NOT AVAILABLE					
19	Amort. and Depl. of Producing Natural Gas Land and Land Rights						
20	Amort. of Underground Storage Land and Land Rights						
21	Amort. of Other Utility Plant						
22	TOTAL In Service (Enter total of lines 18 thru 21)						
23	Leased to Others						
24	Depreciation						
25	Amortization and Depletion						
26	TOTAL Leased to Others (Enter Total of lines 24 and						
27	Held for Future Use						
28	Depreciation						
29	Amortization						
30	TOTAL Held for Future Use (Enter Total of lines 28 and 29)						
31	Abandonment of Leases (Natural Gas)						
32	Amort. of Plant Acquisition Adj						
33	TOTAL Accumulated Provisions (Should agree with li 14 above) (Enter Total of lines 22,26,30,31,and 32)						

ELECTRIC PLANT IN SERVICE

(In addition to Account 101, Electric Plant in Service [Classified], this schedule includes Account 102, Electric Plant Purchased or Sold, Account 103, Experimental Electric Plant Unclassified and Account 106, Completed Construction Not Classified-Electric.)

1. Report below the original cost of electric plant in service according to prescribed accounts.

2. Do not include as adjustments, corrections of additions and retirements for the current or the preceding year. Such items should be included in column (c) or (d) as appropriate.

3. Credit adjustments of plant accounts should be enclosed in parentheses to indicate the negative effect of such amounts.

4. Reclassifications or transfers within utility plant accounts should be shown in column (f). Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, Electric Plant Purchased or Sold. In showing the clearance of Account 102, include in column (c) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

Line No.	Account (a)	Balance at Beginning of year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
1	1. INTANGIBLE PLANT								1
2	(301) Organization	$ 1,230	$	$	$	$	$ 1,230	(301)	2
3	(302) Franchises and Consents	241,023					241,023	(302)	3
4	(303) Miscellaneous Intangible Plant							(303)	4
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	242,253	0	0	0	0	242,253		5
6	2. PRODUCTION PLANT								6
7	A. Steam Production Plant								7
8	(310) Land and Land Rights	106,610					106,610	(310)	8
9	(311) Structures and Improvements	12,408,084	83,932				12,492,016	(311)	9
10	(312) Boiler Plant Equipment	43,566,859	66,201				43,633,060	(312)	10
11	(313) Engines and Engine Driven Generators	0					0	(313)	11
12	(314) Turbogenerator Units	13,570,760	1				13,570,761	(314)	12
13	(315) Accessory Electric Equipment	4,660,835	9,830				4,670,665	(315)	13
14	(316) Misc. Power Plant Equipment	1,680,620	59,394	(1,201)			1,738,813	(316)	14
15	(317) Asset Retirement Costs for Steam Production	4,348,222	83,209				4,431,431	(317)	15
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	80,341,989	302,566	(1,201)	0	0	80,643,355		16
17	B. Nuclear Production Plant								17
18	(320) Land and Land Rights	0					0	(320)	18
19	(321) Structures and Improvements	0					0	(321)	19
20	(322) Reactor Plant Equipment	0					0	(322)	20
21	(323) Turbogenerator Units	0					0	(323)	21
22	(324) Accessory Electric Equipment	0					0	(324)	22
23	(325) Misc. Power Plant Equipment	0					0	(325)	23
24	(326) Asset Retirement Csts for Nuclear Productions	0					0	(326)	
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	0	0	0	0	0	0		25
26	C. Hydraulic Production Plant								26
27	(330) Land and Land Rights	11,181,675					11,181,675	(330)	27
28	(331) Structures and Improvements	19,439,539	455,445	(110,457)			19,784,527	(331)	28
29	(332) Reservoirs, Dams, and Waterways	91,633,406	444,949				92,078,355	(332)	29
30	(333) Water Wheels, Turbines, and Generators	22,969,504	631,523				23,601,027	(333)	30
31	(334) Accessory Electric Equipment	12,527,664	120,234	(3,686)			12,644,211	(334)	31
32	(335) Misc. Power Plant Equipment	4,146,268	247,462				4,393,730	(335)	32
33	(336) Roads, Railroads, and Bridges	1,388,105					1,388,105	(336)	33
34	(337) Asset Retirement Costs for Hydraulic Production	0					0	(337)	34
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	163,286,161	1,899,612	(114,143)		0	165,071,630		35

ELECTRIC PLANT IN SERVICE

(In addition to Account 101, Electric Plant in Service [Classified], this schedule includes Account 102, Electric Plant Purchased or Sold, Account 103, Experimental Electric Plant Unclassified and Account 106, Completed Construction Not Classified-Electric.)

1. Report below the original cost of electric plant in service according to prescribed accounts.

2. Do not include as adjustments, corrections of additions and retirements for the current or the preceding year. Such items should be included in column (c) or (d) as appropriate.

3. Credit adjustments of plant accounts should be enclosed in parentheses to indicate the negative effect of such amounts.

4. Reclassifications or transfers within utility plant accounts should be shown in column (f). Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, Electric Plant Purchased or Sold. In showing the clearance of Account 102, include in column (c) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

Line No.	Account (a)	Balance at Beginning of year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
36	D. Other Production Plant								36
37	(340) Land and Land Rights	$	$	$	$	$	$	(340)	37
38	(341) Structures and Improvements	0					0	(341)	38
39	(342) Fuel Holders, Products and Accessories	0					0	(342)	39
40	(343) Prime Movers	0					0	(343)	40
41	(344) Generators	0					0	(344)	41
42	(345) Accessory Electric Equipment	0					0	(345)	42
43	(346) Misc. Power Plant Equipment	0					0	(346)	43
44	(347) Asset Retirement Costs for Hydraulic Production	0					0	(347)	44
45	TOTAL Other Production Plant (Enter Total of lines 36 thru 44)	0	0	0	0	0	0		45
46	TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 45)	243,628,150	2,202,179	(115,344)	0	0	245,714,985		46
47	3. TRANSMISSION PLANT								47
48	(350) Land and Land Rights	4,657,361	$ 32,202				4,689,563	(350)	48
49	(352) Structures and Improvements	6,741,975	565,615				7,307,591	(352)	49
50	(353) Station Equipment	34,000,140	3,718,250	(362,149)			37,356,242	(353)	50
51	(354) Towers and Fixtures	15,518,423	9,147,549	(45,769)			24,620,204	(354)	51
52	(355) Poles and Fixtures	23,249,822	7,951,384	(371,392)			30,829,814	(355)	52
53	(356) Overhead Conductors and Devices	19,827,308	7,876,026	(415,416)			27,287,918	(356)	53
54	(357) Underground Conduit	0					0	(357)	54
55	(358) Underground Conductors and Devices	0					0	(358)	55
56	(359) Roads and Trails	48,567					48,567	(359)	56
57	(359.1) Asset Retirement Costs for Transmission Plant	0					0	(359.1)	57
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	104,043,596	29,291,027	(1,194,725)	0	0	132,139,898		58
59	4. DISTRIBUTION PLANT								59
60	(360) Land and Land Rights	149,236					149,236	(360)	60
61	(361) Structures and Improvements	1,487,753	(68,463)	(2,168)			1,417,122	(361)	61
62	(362) Station Equipment	7,315,844	2,950,328	(21,245)			10,244,927	(362)	62
63	(363) Storage Battery Equipment	0					0	(363)	63
64	(364) Poles, Towers, and Fixtures	18,483,952	449,878	(91,345)			18,842,485	(364)	64
65	(365) Overhead Conductors and Devices	8,649,074	248,937	(93,859)			8,804,153	(365)	65
66	(366) Underground Conduit	663,097	(6,313)	(6,179)			650,604	(366)	66
67	(367) Underground Conductors and Devices	3,119,152	6,028	(2,826)			3,122,355	(367)	67
68	(368) Line Transformers	44,671,164	2,070,909	(89,727)			46,652,346	(368)	68
69	(369) Services	2,863,478	29,344	(21,129)			2,871,692	(369)	69
70	(370) Meters	7,272,942	440,513	(905)			7,712,550	(370)	70
71	(371) Installations on Customer Premises	226,017	8,360	(9,680)			224,697	(371)	71
72	(372) Leased Property on Customer Premises	0					0	(372)	72
73	(373) Street Lighting and Signal Systems	205,198	7,203	(2,668)			209,733	(373)	73
74	(374) Asset Retirement Cost for Distribution Plant	0					0	(374)	74
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	95,106,908	6,136,723	(341,731)	0	0	100,901,900		75

ELECTRIC PLANT IN SERVICE

(In addition to Account 101, Electric Plant in Service [Classified], this schedule includes Account 102, Electric Plant Purchased or Sold, Account 103, Experimental Electric Plant Unclassified and Account 106, Completed Construction Not Classified-Electric.)

1. Report below the original cost of electric plant in service according to prescribed accounts.

2. Do not include as adjustments, corrections of additions and retirements for the current or the preceding year. Such items should be included in column (c) or (d) as appropriate.

3. Credit adjustments of plant accounts should be enclosed in parentheses to indicate the negative effect of such amounts.

4. Reclassifications or transfers within utility plant accounts should be shown in column (f). Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, Electric Plant Purchased or Sold. In showing the clearance of Account 102, include in column (c) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

Line No.	Account (a)	Balance at Beginning of year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
76	5. GENERAL PLANT								76
77	(389) Land and Land Rights	8,243					8,243	(389)	77
78	(390) Structures and Improvements	495,898					495,898	(390)	78
79	(391) Office Furniture and Equipment	171,471	6,690	(86)			178,075	(391)	79
80	(392) Transportation Equipment	2,550,641	429,822	(22,500)			2,957,963	(392)	80
81	(393) Stores Equipment	0					0	(393)	81
82	(394) Tools, Shop and Garage Equipment	5,381	(1,252)				4,129	(394)	82
83	(395) Laboratory Equipment	62,022		(1,032)			60,990	(395)	83
84	(396) Power Operated Equipment	1,577,046	277,022	(8,288)			1,845,780	(396)	84
85	(397) Communication Equipment	4,182,017	490,132	(198,669)			4,473,480	(397)	85
86	(398) Miscellaneous Equipment	19,177					19,177	(398)	86
87	SUBTOTAL (Enter Total of lines 77 thru 86)	9,071,895			0	0	10,043,734		87
88	(399) Other Tangible Property *	0					0	(399)	88
90	(399.1) Asset Retirement Costs for General Plant	0					0	(399.1)	90
91	TOTAL General Plant (Enter Total of lines 87 thru 90)	9,071,895			0	0	10,043,734		91
92	TOTAL (Accounts 101 and 106)	452,092,803			0	0	489,042,770		92
93	(102) Electric Plant Purchased **								93
94	(Less) (102) Electric Plant Sold **								94
95	(103) Experimental Electric Plant Unclassified								95
96	TOTAL Electric Plant in Service	$ 452,092,803	$	$	$	$	$ 489,042,770		96

* State the nature and use of plant included in this account and if substantial in amount submit a supplementary schedule showing subaccount classification of such plant conforming to the requirements of this schedule.

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

NOTE

Completed Construction Not Classified, Account 106, shall be classified in this schedule according to prescribed accounts, on an estimated basis if necessary, and the entries included in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (c). Likewise, if respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, a tentative distribution of such retirements, on an estimated basis with appropriate contra entry to the account for accumulated depreciation provision, shall be included in column (d). Include also in column (d) reversals of tentative distributions of prior year of unclassified retirements. Attach an insert page showing the account distributions of these tentative classifications in columns (c) and (d) including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

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

1. Report below the information called for concerning accumulated provision for depreciation of electric utility plant.
2. Explain any important adjustments during year.
3. Explain any difference between the amount for book cost of plant retired, line.., column (c), and that reported in the schedule for electric plant in service, pages 401-403, column (d) exclusive of retirements of nondepreciable property.
4. The provisions of account 108 in the Uniform System of Accounts contemplate that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, preliminary closing entries should be made to tentatively functionalize the book cost of the plant retired. In addition, all cost included in retirement work in progress at year end should be included in the appropriate functional classifications.
5. Show separately interest credits under a sinking fund or similar method of depreciation accounting.
6. In section B show the amounts applicable to prescribed functional classifications.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year				
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense				
4	(413) Exp. of Elec. Plt. Leas. to Others				
5	Transportation Expenses-Clearing	INFORMATION NOT AVAILABLE BY STATE ON A SITUS BASIS.			
6	Other Clearing Accounts				
7	Other Accounts (Specify):				
8					
9	TOTAL Deprec. Prov. for Year (Enter Total of lines 3 thru 8)				
10	Net Charges for Plant Retired:				
11	Book Cost of Plant Retired				
12	Cost of Removal				
13	Salvage (Credit)				
14	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 11 thru				
15	Other Debit or Credit Items (Describe)				
16	Balance End of Year (Enter Total of				
17	lines 1, 9, 14, 15, and 16)				

Section B. Balances at End of Year According to Functional Classifications

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
18	Steam Production				
19	Nuclear Production				
20	Hydraulic Production - Conventional				
21	Hydraulic Production - Pumped Storage				
22	Other Production				
23	Transmission				
24	Distribution				
25	General				
26	TOTAL (Enter Total of lines 18 thru 25)				

MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)	Department or Departments Which Use Material (d)
1	Fuel Stock (Account 151)			
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)			
6	Assigned to - Operations and Maintenance	INFORMATION NOT AVAILABLE BY STATE ON A SITUS BASIS.		
7	Production Plant (Estimated)			
8	Transmission Plant (Estimated)			
9	Distribution Plant (Estimated)			
10	Assigned to - Other			
11	TOTAL Account 154 (Enter Total of lines 5 thru 10)			
12	Merchandise (Account 155)			
13	Other Materials and Supplies (Account 156)			
14	Nuclear Materials Held for Sale (Account 157) (Not applicable to Gas Utilities)			
15	Stores Expense Undistributed (Account 163)			
16				
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)			

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

Line No.	Item (a)	Total (b)	Electric (c)	Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Common (g)
1	UTILITY PLANT						
2	In Service						
3	Plant in Service (Classified)	$ 229,463,798	$ 229,463,798				
4	Property Under Capital Leases						
5	Plant Purchased or Sold						
6	Completed Construction not Classified						
7	Experimental Plant Unclassified						
8	TOTAL (Enter Total of lines 3 thru 7)	229,463,798	229,463,798				
9	Leased to Others						
10	Held for Future Use	$ 268,983	268,983				
11	Construction Work in Progress						
12	Acquisition Adjustments						
13	TOTAL Utility Plant (Enter Total of lines 8 thru 12)	229,732,782	229,732,782				
14	Accum. Prov. for Depr., Amort., & Depl.	$ 89,556,458	89,556,458				
15	Net Utility Plant (Enter Total of line 13 less 14)	$ 140,176,324	$ 140,176,324				
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION						
17	In Service						
18	Depreciation	$ 88,493,288	$ 88,493,288				
19	Rights						
20	Amort. of Underground Storage Land and Land Rights						
21	Amort. of Other Utility Plant	$ 1,063,170	1,063,170				
22	TOTAL In Service (Enter total of lines 18 thru 21)	89,556,458	89,556,458				
23	Leased to Others						
24	Depreciation						
25	Amortization and Depletion						
26	TOTAL Leased to Others (Enter Total of lines 24 and 25)						
27	Held for Future Use						
28	Depreciation						
29	Amortization						
30	TOTAL Held for Future Use (Enter Total of lines 28 and 29)						
31	Abandonment of Leases (Natural Gas)						
32	Amort. of Plant Acquisition Adj.						
33	TOTAL Accumulated Provisions (Should agree with line 14 above) (Enter Total of lines 22,26,30,31,and 32)	$ 89,556,458	$ 89,556,458				

ELECTRIC PLANT IN SERVICE	ELECTRIC PLANT IN SERVICE (Continued)
(In addition to Account 101, Electric Plant in Service [Classified], this schedule includes Account 102, Electric Plant Purchased or Sold, Account 103, Experimental Electric Plant Unclassified and Account 106, Completed Construction Not Classified-Electric.) 1. Report below the original cost of electric plant in service according to prescribed accounts. 2. Do not include as adjustments, corrections of additions and retirements for the current or the preceding year. Such items should be included in column (c) or (c) as appropriate.	3. Credit adjustments of plant accounts should be enclosed in parentheses to indicate the negative effect of such amounts. 4. Reclassifications or transfers within utility plant accounts should be shown in column (f). Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, Electric Plant Purchased or Sold. In showing the clearance of Account 102, include in column (c) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
1	1. INTANGIBLE PLANT								1
2	(301) Organization	$ 244					$ 239	(301)	2
3	(302) Franchises and Consents	1,248,518					1,222,664	(302)	3
4	(303) Miscellaneous Intangible Plant	1,265,193					1,192,103	(303)	4
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	$ 2,513,955					$ 2,415,005		5
6	2. PRODUCTION PLANT								6
7	A. Steam Production Plant								7
8	(310) Land and Land Rights							(310)	8
9	(311) Structures and Improvements							(311)	9
10	(312) Boiler Plant Equipment							(312)	10
11	(313) Engines and Engine Driven Generators							(313)	11
12	(314) Turbogenerator Units							(314)	12
13	(315) Accessory Electric Equipment							(315)	13
14	(316) Misc. Power Plant Equipment							(316)	14
15	(317) Asset Retirement Costs for Steam Production Equipment							(317)	15
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	$ 42,286,985					$ 44,732,000		16
17	B. Nuclear Production Plant								17
18	(320) Land and Land Rights							(320)	18
19	(321) Structures and Improvements							(321)	19
20	(322) Reactor Plant Equipment							(322)	20
21	(323) Turbogenerator Units							(323)	21
22	(324) Accessory Electric Equipment							(324)	22
23	(325) Misc. Power Plant Equipment							(325)	23
24	(326) Asset Retirement Costs for Nuclear Production							(326)	
25	TOTAL Nuclear Production Plant (Enter Total of lines 17 thru 24)								25
26	C. Hydraulic Production Plant								26
27	(330) Land and Land Rights							(330)	27
28	(331) Structures and Improvements							(331)	28
29	(332) Reservoirs, Dams, and Waterways							(332)	29
30	(333) Water Wheels, Turbines, and Generators							(333)	30

ELECTRIC PLANT IN SERVICE	ELECTRIC PLANT IN SERVICE (Continued)
(In addition to Account 101, Electric Plant in Service [Classified], this schedule includes Account 102, Electric Plant Purchased or Sold, Account 103, Experimental Electric Plant Unclassified and Account 106, Completed Construction Not Classified-Electric.) 1. Report below the original cost of electric plant in service according to prescribed accounts. 2. Do not include as adjustments, corrections of additions and retirements for the current or the preceding year. Such items should be included in column (c) or (c) as appropriate.	3. Credit adjustments of plant accounts should be enclosed in parentheses to indicate the negative effect of such amounts. 4. Reclassifications or transfers within utility plant accounts should be shown in column (f). Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, Electric Plant Purchased or Sold. In showing the clearance of Account 102, include in column (c) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
31	(334) Accessory Electric Equipment							(334)	31
32	(335) Misc. Power Plant Equipment							(335)	32
33	(336) Roads, Railroads, and Bridges							(336)	33
34	(337) Asset Retirement Costs for Hydraulic Production							(326)	34
35	TOTAL Hydraulic Production Plant (Enter Total of lines 26 thru 3	$ 32,564,876					$ 32,087,497		35
36	D. Other Production Plant								36
37	(340) Land and Land Rights							(340)	37
38	(341) Structures and Improvements							(341)	38
39	(342) Fuel Holders, Products and Accessories							(342)	39
40	(343) Prime Movers							(343)	40
41	(344) Generators							(344)	41
42	(345) Accessory Electric Equipment							(345)	42
43	(346) Misc. Power Plant Equipment							(346)	43
44	(347) Asset Retirement Costs for Other Production							(347)	44
45	TOTAL Other Production Plant (Enter Total of lines 36 thru 44)	$ 23,615,848					$ 22,122,237		45
46	TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 45	98,467,709					98,941,734		46
47	3. TRANSMISSION PLANT								47
48	(350) Land and Land Rights	1,540,411					1,494,619	(350)	48
49	(352) Structures and Improvements	3,100,448					3,196,200	(352)	49
50	(353) Station Equipment	17,069,192					16,778,095	(353)	50
51	(354) Towers and Fixtures	7,167,489					7,585,368	(354)	51
52	(355) Poles and Fixtures	6,109,374					6,539,437	(355)	52
53	(356) Overhead Conductors and Devices	8,392,324					8,730,233	(356)	53
54	(357) Underground Conduit							(357)	54
55	(358) Underground Conductors and Devices							(358)	55
56	(359) Roads and Trails	16,632					16,034	(359)	56
57	(359.1) Asset Retirement Costs for Transmission Plant							(359.1)	57
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	$ 43,395,870					$ 44,339,986		58
59	4. DISTRIBUTION PLANT								59
60	(360) Land and Land Rights	123,895					124,389	(360)	60
61	(361) Structures and Improvements	1,600,539					1,530,958	(361)	61
62	(362) Station Equipment	6,960,940					9,789,607	(362)	62
63	(363) Storage Battery Equipment	0					0	(363)	63
64	(364) Poles, Towers, and Fixtures	18,483,952					18,842,485	(364)	64
65	(365) Overhead Conductors and Devices	8,649,074					8,804,153	(365)	65
66	(366) Underground Conduit	663,097					650,604	(366)	66
67	(367) Underground Conductors and Devices	3,119,152					3,122,355	(367)	67
68	(368) Line Transformers	19,367,860					19,480,444	(368)	68
69	(369) Services	2,863,478					2,871,692	(369)	69
70	(370) Meters	2,692,878					2,913,941	(370)	70
71	(371) Installations on Customer Premises	226,017					224,697	(371)	71

ELECTRIC PLANT IN SERVICE	ELECTRIC PLANT IN SERVICE (Continued)
(In addition to Account 101, Electric Plant in Service [Classified], this schedule includes Account 102, Electric Plant Purchased or Sold, Account 103, Experimental Electric Plant Unclassified and Account 106, Completed Construction Not Classified-Electric.) 1. Report below the original cost of electric plant in service according to prescribed accounts. 2. Do not include as adjustments, corrections of additions and retirements for the current or the preceding year. Such items should be included in column (c) or (c) as appropriate.	3. Credit adjustments of plant accounts should be enclosed in parentheses to indicate the negative effect of such amounts. 4. Reclassifications or transfers within utility plant accounts should be shown in column (f). Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, Electric Plant Purchased or Sold. In showing the clearance of Account 102, include in column (c) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
72	(372) Leased Property on Customer Premises							(372)	72
73	(373) Street Lighting and Signal Systems	205,198					209,733	(373)	73
74	(374) Asset Retirement Costs for Distribution Plant							(374)	74
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	$ 64,956,080					$ 68,565,058		75
76	5. GENERAL PLANT								76
77	(389) Land and Land Rights	707,961					693,603	(389)	77
78	(390) Structures and Improvements	4,570,892					4,640,784	(390)	78
79	(391) Office Furniture and Equipment	1,960,200					1,953,469	(391)	79
80	(392) Transportation Equipment	3,169,200					3,174,564	(392)	80
81	(393) Stores Equipment	82,691					94,360	(393)	81
82	(394) Tools, Shop, and Garage Equipment	323,468					335,600	(394)	82
83	(395) Laboratory Equipment	540,303					531,493	(395)	83
84	(396) Power Operated Equipment	595,204					630,991	(396)	84
85	(397) Communication Equipment	2,296,939					2,318,420	(397)	85
86	(398) Miscellaneous Equipment	238,162					249,672	(398)	86
87	SUBTOTAL (Enter Total of lines 77 thru 86)	14,485,020					14,622,957		87
88	(399) Other Tangible Property *							(399)	88
89	(399.1) Asset Retirement Costs for General Plant							(399.1)	89
90	TOTAL General Plant (Enter Total of lines 87, 88 and 89)	14,485,020					14,622,957		90
91	TOTAL (Accounts 101 and 106)	223,818,635					228,884,742		91
92	(102) Electric Plant Purchased **								92
93	(Less) (102) Electric Plant Sold **								93
94	Asset Retirement Obligations (ARO)	294,300					579,057		94
95	TOTAL Electric Plant in Service	$ 224,112,935					$ 229,463,798		95

* State the nature and use of plant included in this account and if substantial in amount submit a supplementary schedule showing subaccount classification of such plant conforming to the requirements of this schedule.

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

NOTE

Completed Construction Not Classified, Account 106, shall be classified in this schedule according to prescribed accounts, on an estimated basis if necessary, and the entries included in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (c). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, a tentative distribution of such retirements, on an estimated basis with appropriate contra entry to the account for accumulated depreciation provision, shall be included in column (d). Include also in column (d) reversals of tentative distributions of prior year of unclassified retirements. Attach an insert page showing the account distributions of these tentative classifications in columns (c) and (d) including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

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

1. Report below the information called for concerning accumulated provision for depreciation of electric utility plant.
2. Explain any important adjustments during year.
3. Explain any difference between the amount for book cost of plant retired, line.., column (c), and that reported in the schedule for electric plant in service, pages 401-403, column (d) exclusive of retirements of nondepreciable property.
4. The provisions of account 108 in the Uniform System of Accounts contemplate that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, preliminary closing entries should be made to tentatively functionalize the book cost of the plant retired. In addition, all cost included in retirement work in progress at year end should be included in the appropriate functional classifications.
5. Show separately interest credits under a sinking fund or similar method of depreciation accounting.
6. In section B show the amounts applicable to prescribed functional classifications.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	$	$		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	5,548,792	5,548,792		
4	(413) Exp. of Elec. Plt. Leas. to Others				
5	Transportation Expenses-Clearing				
6	Other Clearing Accounts				
7	Other Accounts (Specify)				
8					
9	TOTAL Deprec. Prov. for Year (Enter Total of lines 3 thru 8)	5,548,792	5,548,792		
10	Net Charges for Plant Retired				
11	Book Cost of Plant Retired				
12	Cost of Removal				
13	Salvage (Credit)				
14	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 11 thru 13				
15	Other Debit or Credit Items (Describe)				
16	Balance End of Year (Enter Total of				
17	lines 1, 9, 14, 15, and 16)	$ 5,548,792	$ 5,548,792		

Section B. Balances at End of Year According to Functional Classifications

Line No.	Item (a)	Total (c+d+e) (b)	Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
18	Steam Production	$ 21,981,256	$ 21,981,256		
19	Nuclear Production				
20	Hydraulic Production - Conventional	16,541,860	16,541,860		
21	Hydraulic Production - Pumped Storage				
22	Other Production	3,705,622	3,705,622		
23	Transmission	13,902,465	13,902,465		
24	Distribution	27,511,386	27,511,386		
25	General	4,386,541	4,386,541		
26	FAS 143 Adj &/or Disallowed Cost	464,159	464,159		
27	TOTAL (Enter Total of lines 18 thru 26)	$ 88,493,288	$ 88,493,288		

MATERIALS AND SUPPLIES

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

Line No.	Account (a)	Balance at Beginning of Year (b)	Balance at End of Year (c)	Department or Departments Which Use Material (d)
1	Fuel Stock (Account 151)	$ 2,447,942	$ 2,821,708	
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)			
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	724,920	714,250	
8	Transmission Plant (Estimated)	478,799	460,708	
9	Distribution Plant (Estimated)	880,894	953,899	
10	Assigned to - Other	64,844	79,973	
11	TOTAL Account 154 (Enter Total of lines 5 thru 10)	2,149,457	2,208,831	
12	Merchandise (Account 155)			
13	Other Materials and Supplies (Account 156)			
14	Nuclear Materials Held for Sale (Account 157) (Not applicable to Gas Utilities)			
15	Stores Expense Undistributed (Account 163)	217,731	187,342	
16				
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	$ 4,815,130	$ 5,217,881	

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	Megawatt Hours (b)	Line No.	Item (a)	Megawatt Hours (b)
1	SOURCES OF ENERGY		20	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		21	Sales to Ultimate Consumers (Including Interdepartmental Sales)	
3	Steam.......... Steam..........				
4	Nuclear..........		22	Sales for Resale	
5	Hydro-Conventional..........		23	Energy Furnished Without Charge	
6	Hydro-Pumped Storage..........	INFORMATION	24	Energy Used by the Company	INFORMATION
7	Other..........			(Excluding Station Use):	
8	Less Energy for Pumping..........	NOT	25	Electric Department Only	NOT
9	Net Generation (Enter Total of lines 3 thru 8)..........	AVAILABLE	26	Energy Losses:	AVAILABLE
10	Purchases..........		27	Transmission and Conversion Losses	
11	Interchanges:		28	Distribution Losses	
12	In (gross)..........		29	Unaccounted for Losses	
13	Out (gross)..........		30	TOTAL Energy Losses	
14	Net Interchanges (Lines 12 & 13)..........		31	Energy Losses as Percent of Total on Line 19	
15	Transmission for/by Others (Wheeling)				
16	Received (MWH)		32	TOTAL (Enter Total of lines 21, 22, 23, 25, and 30)	
17	Delivered (MWh)				
18	Net Transmission (lines 16 & 17)..........				
19	TOTAL (Enter Total of lines 9, 10, 14, and 18)..........				

MONTHLY PEAKS AND OUTPUT

1. Report below the information called for pertaining to simultaneous peaks established monthly (in megawatts) and monthly output (in megawatt-hours) for the combined sources of electric energy of respondent.
2. Report in column (b) the respondent's maximum MW load as measured by the sum of its coincidental net generation and purchases plus or minus net interchange, minus temporary deliveries (not interchange) Show monthly peak including such emergency deliveries of emergency power to another system. in a footnote and briefly explain the nature of the emergency. There may be cases of commingling of purchases and exchanges and "wheeling," also of direct deliveries by the supplier to customers of the reporting utility wherein segregation of MW demand for determination of peaks as specified by this report may be unavailable. In these cases, report peaks which include these intermingled transactions. Furnish an explanatory note which indicates, among other things, the relative significance of the deviation from basis otherwise applicable. If the individual MW amounts of such totals are needed for billing under separate rate schedules and are estimated, give the amount and basis of estimate.
3. State type of monthly peak reading (instantaneous 15, 30, or 60 minutes integrated).
4. Monthly output is the sum of respondent's net generation for load and purchases plus or minus net interchange and plus or minus net transmission or wheeling. Total for the year must agree with line 19 above.
5. If the respondent has two or more power systems not physically connected, furnish the information called for below for each system.

NAME OF SYSTEM: OREGON RETAIL ONLY

Line No.	Month (a)	MONTHLY PEAK Megawatts (b)	Day of Week (c)	Day of Month (d)	Hour (e)	Type of Reading (f)	Monthly Output (MWh) (See Instr. 4) (g)
33	January	105.22	Friday	2	9 A.M.	60 Min. Int	61,119
34	February	82.05	Monday	23	8 A.M.	" " "	44,035
35	March	93.84	Wednesday	4	8 A.M.	" " "	53,325
36	April	70.96	Tuesday	28	10 P.M.	" " "	51,617
37	May	78.00	Monday	4	8 P.M.	" " "	56,155
38	June	130.07	Tuesday	30	4 P.M.	" " "	71,570
39	July	126.22	Wednesday	1	7 P.M.	" " "	70,139
40	August	120.23	Wednesday	12	6 P.M.	" " "	70,260
41	September	95.86	Tuesday	1	7 P.M.	" " "	51,449
42	October	79.84	Saturday	10	6 P.M.	" " "	53,378
43	November	93.15	Monday	30	7 P.M.	" " "	56,108
44	December	99.34	Tuesday	1	8 A.M.	" " "	64,348
45	TOTAL	1,174.78					703,503

MISCELLANEOUS GENERAL EXPENSES (Account 930.2)

Report below the information called for concerning items included in miscellaneous general expenses.

Line No.	Items (a)	Total (b)	Amount Applicable to Oregon (c)	Amount Applicable to Other States (d)
1	Industry association dues	$ 505,604	$ 22,531	$ 483,073
2	Nuclear power research expenses (elec.)			
3	Other experimental and general research expenses			
4	Publishing and distributing information and reports to stockholders;			
5	trustee, registrar, and transfer agent fees and expenses, and other			
6	expenses of servicing outstanding securities of the respondent	1,602,436	71,409	1,531,027
7	Other expenses (items of $100 or more must be listed separately show-			
8	ing the (1) purpose, (2) recipient, and (3) amount of such items.			
9	Amounts of less than $100 may be grouped by classes if the number	64,833	2,889	61,944
10	of items so grouped is shown)			
11				
12				
13	Directors' fees and expenses (see detail on page 39)	872,227	38,869	833,358
14				
15	Memberships and contributions (see detail on page 39)	2,399,753	106,939	2,292,814
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
35				
36				
37				
38				
39	**TOTAL**	$ 5,380,020	$ 242,637	$ 5,202,216

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (Continued)

Report below the information called for concerning items included in miscellaneous general expenses.

Line No.	Items (a)	Total (b)	Amount Applicable to Oregon (c)	Amount Applicable to Other States (d)
1				
2	Directors' Fees and Expenses:			
3	Christine King-Fees and expenses	$ 88,359	3,938	84,421
4	Dennis Johnson - Fees and expenses	70,290	3,132	67,158
5	J LaMont Keen - Fees and expenses	64,350	2,868	61,482
6	Jan Packwood-Fees and expenses	26,812	1,195	25,617
7	Joan Smith - Fees and expenses	35,395	1,577	33,818
8	Judith Johansen-Fees and expenses	78,331	3,491	74,840
9	Richard Dahl - Fees	91,575	4,081	87,494
10	Richard Navarro - Fees and expenses	65,066	2,900	62,166
11	Robert A Tinstman Fees and expenses	170,775	7,610	163,165
12	Ronald Jibson - Fees and expenses	74,473	3,319	71,154
13	Thomas Carlile - Fees and expenses	76,230	3,397	72,833
14	Thomas Wilford - Fees and expenses	30,571	1,362	29,209
15	SUBTOTAL	872,227	38,869	833,357
16				
17	Other Expenses >$5,000:			
18	Bank of New York	$ 13,925	621	13,304
19	Payroll Related Expenses	22,311	994	21,317
20	Total Electric	5,175	231	4,944
21	Union Ban	9,680	431	9,249
22	Miscellaneious <$5,000	13,742	612	13,130
23	SUBTOTAL	64,833	2,889	61,944
24	Miscellaneous General Management Expenses:			
25	American Stock Transfer & Trust	65,293	2,910	62,383
26	Bloomberg Finance LP	10,146	452	9,694
27	Broadridge Financial Solutions	46,949	2,092	44,857
28	Deutche Bank	30,000	1,337	28,663
29	E Source	39,906	1,778	38,128
30	Moody's Analytics	32,310	1,440	30,870
31	NASDAQ Corp Solutions	62,573	2,788	59,785
32	New York Stock Exchange	50,163	2,235	47,928
33	Payroll Related Expenses	175,051	7,801	167,250
34	PR Newswire	14,813	660	14,153
35	Rivel Research Group	15,840	706	15,134
36	Stock Based Compensation	949,993	42,334	907,659
37	Wells Fargo Shareowner Services	107,626	4,796	102,830
38	Miscellaneous General Management Expenses:	1,773	79	1,694
39	SUBTOTAL	1,602,436	71,409	1,531,028
40				
41	Memberships and Contributions:			
42	Arizona State University	50,000	2,228	47,772
43	Associated Taxpayers of Idaho - Membership	22,000	980	21,020
44	Boston College Center for Corporation	5,000	223	4,777
45	Business Plus	5,000	223	4,777
46	Ceati International	13,350	595	12,755
47	Chamber of Commerce	90,135	4,017	86,118
48	Corporate Executive Board	87,535	3,901	83,634
49	Idaho Associaton of Commerce and Industry	15,000	668	14,332
50	Idaho Technology Council	12,500	557	11,943
51	National Assoc of Directors	7,125	318	6,807
52	National HydroPower Association	36,069	1,607	34,462
53	North American Energy Standard	7,000	312	6,688
54	Northwest Power Pool	342,472	15,261	327,211
55	Pacific NW Utilities-Membership	40,160	1,790	38,370
56	SNL Financial Unlimited Subscription	23,200	1,034	22,166
57	Western Alliance for Economics	2,500	111	2,389
58	Western Electricity Coordinating Council	1,604,339	71,494	1,532,845
59	Western Energy Institute	30,794	1,372	29,422
60	Misc Memberships under $2,000	5,574	248	5,326
61	SUBTOTAL	2,399,753	106,939	2,292,814
62				
63	**TOTAL**	$ 4,939,249	$ 217,217	$ 4,722,032

OFFICERS

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

2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and date change in incumbency was made.

3. Utilities which are required to file similar data with the Securities and Exchange Commission, may substitute a copy of item 4 of Regulation S-K identified as

Line No.	Title (a)	Name of Officer (b)	Salary for year Total	Salary for year Oregon
1				
2	President & Chief Executive Officer....................................	Darrel T Anderson	$ 675,000	$ 30,080
3				
4	Executive Vice President, Chief Operation Officer................	Dan Minor	460,000	20,499
5				
6	Sr Vice President, General Counsel	Rex Blackburn	350,000	15,597
7				
8	Senior Vice President, CFO and Treasurer	Steven R. Keen	345,000	15,374
9				
10	Senior Vice President, Power Supply...................................	Lisa Grow	320,000	14,260
11				
12	Vice President, Public Affairs..	Jeffrey Malmen	260,000	11,586
13				
14	Senior Vice President, Customer Operations.......................	Vern Porter	260,000	11,586
15				-
16	Vice President, Human Resources, Admin Services, & CIO..	Lonnie Krawl	250,000	11,141
17				-
18	Vice President Chief Risk Officer	Lori Smith	242,000	10,784
19				-
20	Vice President, Controller & Chief Accounting Officer...........	Ken Petersen	235,000	10,472
21				-
22	Vice President, Regulatory Affairs..	Gregory Said	217,000	9,670
23				-
24	Corporate Secretary...	Patrick Harrington	188,000	8,378
25				-
26	Vice President, Customer Operations	Warren Kline (1)	159,750	7,119
27				-
28	Vice President, Human Resources & Corp Sevices	Luci McDonald (2)	127,307	5,673
29				
30				
31	(1) Retirement effective 6/30/2015. Base shows YTD wages			
32	(2) Retirement effective 5/31/2015. Base shows YTD wages			
33				
34				
35				
36				
37				
38				
39				

POLITICAL ADVERTISING

INSTRUCTIONS: List all payments for advertising, the purpose of which is to aid or defeat any measure before the people or to promote or prevent the enactment of any national, state, district or municipal legislation. Give the specific purpose of such advertising, when and where placed, and the account or accounts charged. Report whole dollars only. Provide a total for each account and a grand total.

Description	Account Charged	Amount
None		

POLITICAL CONTRIBUTIONS

INSTRUCTIONS: List all payments or contributions to persons and organizations for the purpose of aiding or defeating any measure before the people or to promote or prevent the enactment of any national, state, district or municipal legislation. The purpose of all contributions or payments should be clearly explained.
Report whole dollars only. Provide a total for each account and a grand total.

Description	Account Charged	Amount
ABBY LEE FOR STATE SENATE	426.400	$ 500
ADA COUNTY LINCOLN DAY ASSOCIA	"	2,000
ALAN OLSEN FOR STATE SENATE	"	1,000
ANDRUS CENTER FOR PUBLIC POLIC	"	1,250
BASQUE CENTER	"	250
BIETER FOR BOISE	"	1,000
BOB NONINI FOR STATE SENATE	"	500
BRAD LITTLE FOR IDAHO	"	75
BRAD WITT FOR STATE REPRESENTA	"	750
BRANDON HIXON FOR STATE REPRES	"	500
BRENT CRANE FOR STATE REPRESEN	"	500
CAMPAIGN TO ELECT BETSY JOHNSO	"	1,000
CAROLINE TROY FOR STATE REPRES	"	500
CHAMBER OF COMMERCE	"	2,500
CHERIE BUCKNER-WEBB FOR STATE	"	500
CHUCK WINDER FOR STATE SENATE	"	1,000
CLARK KAUFFMAN FOR STATE REPRE	"	300
CLIFF BAYER FOR STATE SENATOR	"	500
COMMITTEE TO ELECT MIKE MCLANE	"	1,500
COMMITTEE TO RE-ELECT GREG SMI	"	1,000
CURT MCKENZIE FOR STATE SENATE	"	500
DEBORAH BOONE FOR STATE	"	500
ELAINE SMITH FOR STATE	"	300
FRED MARTIN FOR STATE SENATE	"	500
FRED WOOD FOR STATE REPRESENTA	"	500
FRIENDS OF ARNIE ROBLAN	"	250
FRIENDS OF BETSY JOHNSON	"	250
FRIENDS OF CHRIS EDWARDS	"	1,250
FRIENDS OF GINNY BURDICK	"	1,000
FRIENDS OF JENNIFER WILLIAMSON	"	1,000
FRIENDS OF JESSICA PEDERSON	"	1,000
FRIENDS OF LEE BEYER	"	250
FRIENDS OF RICHARD DEVLIN	"	500
FRIENDS OF TINA KOTEK	"	1,500
GARY COLLINS FOR STATE	"	500
GLENNS FERRY THEATRE	"	50
GRANT BURGOYNE FOR STATE SENAT	"	500
GREG BARRETO FOR HD 58	"	500

POLITICAL CONTRIBUTIONS

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Report whole dollars only. Provide a total for each account and a grand total.

Description	Account Charged	Amount
GREG CHANEY FOR STATE REPRESEN	426.400	750
HAHN,RICHARD L	"	134
HOUSE REPUBLICAN CAUCUS	"	500
IDAHO DEMOCRATIC LEGISLATIVE C	"	100
IDAHO INAUGURATION CELEBRATION	"	6,000
IDAHO MINING ASSOCIATION	"	6,125
IDAHO PRIOR APPROPRIATIONS DOCTRINE - REFUND	"	(180)
IDAHO PROSPERITY FUND	"	14,750
IDAHO STATE DEMOCRAT PARTY	"	1,000
IDAHO STATE SOCIETY	"	12,296
IDAHO TRANSPORTATION COALITION	"	1,000
IDAHO WATER USERS ASSOCIA	"	500
ILANA RUBLE FOR STATE REPRESEN	"	500
JANET TRUJILLO FOR STATE REPRE	"	300
JANIE WARD-ENGELKING FOR STATE	"	500
JEFF REARDON FOR OREGON	"	500
JEFF THOMPSON FOR STATE REPRES	"	500
JIM GUTHRIE FOR STATE SENATE	"	300
JIM RICE FOR STATE SENATE	"	750
JOHN DAVIS FOR OREGON	"	1,000
JOHN RUSCHE FOR STATE REPRESEN	"	750
JOHN VANDERWOUDE FOR REPRESENT	"	500
JUDY BOYLE FOR STATE REPRESENT	"	300
JULIE VAN ORDEN FOR STATE REPR	"	300
KELLEY PACKER FOR STATE REPRES	"	300
KELLY ANTHON FOR STATE SENATE	"	500
KEN ANDRUS FOR STATE REPRESENT	"	300
KEN HELM FOR HD 34	"	750
LAWERENCE DENNEY FOR IDAHO	"	2,500
LEADERSHIP FUND, THE	"	1,000
LEE HEIDER FOR STATE SENATE	"	500
LUKE MALEK FOR STATE REPRESENT	"	500
MARC GIBBS FOR STATE REPRESENT	"	500
MARV HAGEDORN FOR STATE SENATE	"	500
MAT ERPELDING FOR STATE REPRES	"	500
MERRILL BEYELER FOR STATE REPR	"	500
MICHELLE STENNETT FOR STATE SE	"	750
MIKE MOYLE FOR STATE REPRESENT	"	750

POLITICAL CONTRIBUTIONS

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Report whole dollars only. Provide a total for each account and a grand total.

Description	Account Charged	Amount
NATIONAL HYDROPOWER ASSOC	426.400	10,000
NEIL ANDERSON FOR STATE REPRES	"	300
PAT MCDONALD FOR STATE REPRESE	"	500
PAUL ROMRELL FOR STATE REPRESE	"	300
PAUL SHEPHERD FOR STATE REPRES	"	300
PETER COURTNEY FOR STATE SENAT	"	1,500
PORTLAND GENERAL ELECTRIC	"	500
POST-REGISTER, THE	"	5,000
PUGET SOUND ENERGY FEDERAL GOV	"	500
RICK YOUNGBLOOD FOR STATE REPR	"	500
ROBERT ANDERST FOR STATE REPRE	"	500
SCOTT BEDKE FOR STATE REPRESEN	"	750
SENATE REPUBLICAN CAUCUS	"	500
SHAWN KEOUGH FOR STATE SENATE	"	1,000
SOUTH DAKOTA ELECTRIC UTILITY	"	513
STEVE VICK FOR STATE SENATOR	"	500
TAMMY DE WEERD FOR MAYOR	"	1,000
TERRY GESTRIN FOR STATE REPRES	"	500
THE KATE BROWN COMMITTEE	"	5,000
TIM KNOPP FOR STATE SENATE	"	500
TODD LAKEY FOR STATE SENATE	"	500
TRAVIS JEFFRIES, P A	"	500
VAN BURTENSHAW FOR STATE REPRE	"	500
WENDY HORMAN FOR STATE REPRESE	"	300
Total Political Contributions		**$ 118,963**

EXPENDITURES TO ANY PERSON OR ORGANIZATION HAVING AN AFFILIATED INTEREST FOR SERVICES, ETC.

INSTRUCTIONS: Report all expenditures to any person or organization having an affiliated interest for service, advice, auditing, associating, sponsoring, engineering, managing, operating, financial, legal or other services. See Oregon Revised Statute 757.015 for definition of "affiliated interest." Give reference if such expenditures have in the past been approved by the Commission. Describe the services received and the account or accounts charged. Report whole dollars only.

Description	Account Charged	Total Amount	Amount Assigned to Oregon
Idaho Power does not have any expenditures to its affiliated companies			

INSTRUCTIONS: List all donations made by the utility during the year and the accounts charged (Items less than $1,000 may be consolidated by category stating the number of organizations included). Give the name city and state of each organization to whom a donation has been made. Group donations under headings such as:

1. Contributions to and memberships in charitable organizations
2. Organizations of the utility industry
3. Technical and professional organizations
4. Commercial and trade organizations
5. All other organizations and kinds of donations and contributions

List donations by type and group by the accounts charged. Report whole dollars only. Provide a total for each group

Description	Account Number	Total Amount	Amount Assigned to Oregon
IDACORP	426101	58,699	None
IDACORP EMPLOYEES	426101	161,301	"
TOTAL MATCHING EMPLOYEE COMMUNITY SERVICE FUND	**426101**	**220,000**	
AMERICAN RED CROSS OF GREATER	426102	1,000	None
BOISE RESCUE MISSION	"	5,000	"
CANYON COUNTY FESTIVAL	"	1,539	"
DESIGNS BY DE	"	2,125	"
FAMILY ADVOCATE PROGRAM	"	1,500	"
GLANBIA CHARITY CHALLENGE	"	1,000	"
IDAHO COMMISSION ON HISPA	"	2,000	"
LUPO,MARK J	"	1,686	"
MARTIN,FRANCES J	"	2,500	"
METRO MEALS ON WHEELS	"	1,000	"
SHRINER HOSPITALS FOR CHILDREN	"	1,000	"
ST ALPHONSUS FESTIVAL OF TREES	"	5,000	"
ST LUKES HEALTH FOUNDATION	"	5,000	"
WESTERN IDAHO TRAINING CO, INC	"	1,000	"
Misc Health and Human Services - 41 Organizations < $1,000	"	15,128	"
TOTAL HEALTH & HUMAN SERVICES	**426102**	**46,478**	
ACCESS TO JUSTICE IDAHO	426103	2,500	None
ANDRUS CENTER FOR PUBLIC POLIC	"	2,000	"
BAKER COUNTY FAIR - HALFWAY	"	1,098	"
BARRETTO,LINDSAY M	"	6,508	"
BOYS & GIRLS CLUB OF ADA CO	"	2,500	"
CALDWELL VETERANS MEMORIAL HAL	"	1,000	"
CHAMBER OF COMMERCE	"	12,700	"
CROUCH/GARDEN VALLEY MUSEUM	"	1,210	"
FRIENDS OF ZOO BOISE	"	1,000	"
FUNDSY	"	1,300	"
GARDEN CITY LIBRARY FOUNDATION	"	1,000	"

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List donations by type and group by the accounts charged. Report whole dollars only. Provide a total for each group

Description	Account Number	Total Amount	Amount Assigned to Oregon
GLANBIA CHARITY CHALLENGE	426103	5,000	None
GO LEAD IDAHO	"	2,000	"
HAILEY ICE INC	"	5,000	"
IDAHO COMMUNITY FOUNDATION	"	2,500	"
IDAHO FOODBANK	"	2,750	"
IDAHO HOUSING & FINANCE ASSOC	"	3,000	"
IDAHO HUMANE SOCIETY	"	13,075	"
IDAHO PATRIOT THUNDER RIDE	"	1,000	"
IDAHO SALMON AND STEELHEAD DAY	"	2,500	"
IDAHO STATE UNIVERSITY	"	2,500	"
IDAHO STATE VETERANS CEMETERY	"	1,500	"
JAIALDI	"	5,000	"
LIGHTHOUSE CHRISTIAN SCHOOL	"	2,500	"
LIONS CLUB	"	1,050	"
LUPO,MARK J	"	4,298	"
MAGIC VALLEY TRAIL ENHANCEMENT	"	5,000	"
MCPAWS REGIONAL ANIMAL SHELTER	"	1,250	"
NEIGHBORHOOD HOUSING	"	4,000	"
PORTNEUF GREENWAY FOUNDATION	"	1,000	"
PORTNEUF VALLEY PAINTFEST	"	1,000	"
ROTARY CLUB	"	1,150	"
ROTARY CLUB OF POCATELLO	"	1,500	"
STUTZMAN,SHARON E	"	1,057	"
TREASURE VALLEY NAACP	"	1,500	"
TWIN FALLS COUNTY HISTORICAL S	"	2,500	"
WASSMUTH CENTER FOR HUMAN RIGH	"	1,000	"
WEWERS,BRYAN J	"	2,199	"
WOMEN'S & CHILDREN'S ALLIANCE	"	5,000	"
Misc Civic and Community Serivices - 176 Organizations < $1,000	"	56,705	"
TOTAL CIVIC & COMMUNITY	**426103**	**171,349**	

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List donations by type and group by the accounts charged. Report whole dollars only. Provide a total for each group

Description	Account Number	Total Amount	Amount Assigned to Oregon
BASQUE MUSEUM AND CULTURAL CEN	426104	2,500	None
BOISE ART MUSEUM	"	3,000	"
BOISE CONTEMPORARY THEATER INC	"	2,000	"
BOISE MUSIC WEEK	"	1,000	"
BOISE PHILHARMONIC ASSOCIATION	"	2,500	"
CHILDREN'S HOME SOCIETY OF ID	"	1,250	"
IDAHO ACADEMIC DECATHLON	"	1,500	"
IDAHO SHAKESPEARE FESTIVAL	"	3,500	"
LOG CABIN LITERARY CENTER	"	2,000	"
MAGIC VALLEY SYMPHONY ORCHESTR	"	1,000	"
MERIDIAN SYMPHONY ORCHESTRA	"	1,000	"
Misc Culture and Arts - 15 Organizations <$1,000	"	4,625	"
TOTAL CULTURE & ARTS	**426104**	**25,875**	
Misc Volunteer Involvement Programs- 39 Organizations <$1,000	426106	5,300	None
TOTAL VOLUNTEER INVOLVEMENT PROGRAM	**426106**	**5,300**	
SALVATION ARMY	426107	18,555	None
TOTAL PROJECT SHARE	**426107**	**18,555**	
Misc Environment and Conservation Programs- 9 Organizations <$1	426108	1,570	None
TOTAL ENVIRONMENT & CONSERVATION	**426108**	**1,570**	
CHAMBER OF COMMERCE, BOISE	426109	5,000	None
CITY OF BOISE HERITAGE FUND	"	20,000	"
IDAHO GOVERNERS CUP	"	17,000	"
SALVATION ARMY	"	28,334	"
TEACH FOR AMERICA	"	10,000	"
THE FIRST TEE OF IDAHO	"	1,000	"
UNIVERSITY OF IDAHO FOUNDATION	"	1,000	"
TOTAL NON-PROGRAM	**426109**	**82,334**	

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List donations by type and group by the accounts charged. Report whole dollars only. Provide a total for each group

Description	Account Number	Total Amount	Amount Assigned to Oregon
BLACKFOOT HIGH SCHOOL	426110	2,500	None
BOISE STATE UNIVERSITY COLLEGE	"	2,000	"
COLLEGE OF IDAHO	"	2,500	"
COLLEGE OF SOUTHERN IDAHO	"	3,030	"
COLLEGE OF WESTERN IDAHO	"	1,250	"
DISCOVERY CENTER OF IDAHO	"	2,500	"
JUNIOR ACHIEVEMENT OF IDAHO	"	5,150	"
LEARNING LAB	"	1,000	"
SOCIETY OF WOMEN ENGINEERS	"	2,000	"
Misc Education Programs - 53 Organizations <$1,000	"	13,132	"
TOTAL EDUCATION	**426110**	**35,062**	
BOISE STATE UNIVERSITY	426111	6,000	None
BOISE STATE UNIVERSITY HONORS	"	2,000	"
BRIGHAM YOUNG UNIVERSITY	"	6,000	"
BRIGHAM YOUNG UNIVERSITY - HAW	"	2,000	"
BRIGHAM YOUNG UNIVERSITY CES A	"	2,000	"
CARROLL COLLEGE	"	2,000	"
COLLEGE OF CHARLESTON	"	2,000	"
COLLEGE OF WESTERN IDAHO	"	2,000	"
IDAHO STATE UNIVERSITY	"	17,000	"
MONTANA STATE UNIVERSITY	"	2,000	"
NORTHWEST NAZARENE UNIVERSITY	"	2,000	"
TREASURER UNITED STATES MILITA	"	2,000	"
UNIVERSITY OF IDAHO	"	6,000	"
UNIVERSITY OF NEVADA	"	2,000	"
UTAH STATE UNIVERSITY	"	2,000	"
UTAH VALLEY UNIVERSITY	"	2,000	"
TOTAL SCHOLARSHIP PROGRAM	**426111**	**59,000**	
BOISE STATE UNIVERSITY	426112	2,950	

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2. Organizations of the utility industry
3. Technical and professional organizations
4. Commercial and trade organizations
5. All other organizations and kinds of donations and contributions

List donations by type and group by the accounts charged. Report whole dollars only. Provide a total for each group

Description	Account Number	Total Amount	Amount Assigned to Oregon
BRIGHAM YOUNG UNIVERSITY	426112	1,000	None
COLLEGE OF IDAHO	"	1,500	"
IDAHO STATE UNIVERSITY	"	3,225	"
NORTHWEST NAZARENE UNIVERSITY	"	2,000	"
UNIVERSITY OF IDAHO FOUNDATION	"	8,325	"
UNIVERSITY OF WISCONSIN	"	1,000	"
Misc Match Higher Education - 5 Organizations <$1000	"	1,050	"
TOTAL MATCH HIGHER EDUCATION	**426112**	**21,050**	"
CHAMBER OF COMMERCE	426121	2,922	"
DESTINATION CALDWELL	"	5,750	"
DOWNTOWN BOISE ASSOCIATION	"	3,000	"
EASTERN IDAHO ECONOMIC	"	4,750	"
GREAT RIFT BUSINESS DEVELOPMENT	"	2,490	"
IDAHO WINE COMMISSION	"	1,048	"
KUNA, CITY OF	"	2,801	"
LEMHI COUNTY ECONOMIC DEVELOPMENT	"	2,884	"
NAMPA, CITY OF	"	4,000	"
SOUTHERN IDAHO ECONOMIC DEVELOPMENT	"	1,750	"
SOUTHERN IDAHO RURAL DEVELOPMENT	"	3,750	"
SUN VALLEY ECONOMIC DEVELOPMENT	"	3,000	"
VALLEY COUNTY ECONOMIC DEVELOPMENT	"	1,496	"
WESTERN ALLIANCE FOR ECONOMIC	"	1,750	"
Misc Economic Recovery - 6 Organizations <$1,000	"	1,865	"
TOTAL ECONOMIC RECOVERY	**426121**	**43,257**	"
SOLDIER MTN SEARCH AND RESCUE	426130	10,000	"
MALHEUR COUNTY SHERIFF"S OFFICE	"	10,000	"
Misc Non-Cash Contributions <$1,000	"	1,130	"
TOTAL NON-CASH CONTRIBUTIONS	**426130**	**21,130**	"
TOTAL CONTRIBUTIONS ACCOUNT 426.1		**750,960**	"

DONATIONS OR PAYMENTS FOR SERVICES RENDERED BY PERSONS OTHER THAN EMPLOYEES AND CHARGED TO OREGON OPERATING ACCOUNTS

1. Report for each service rendered (including materials furnished incidental to the service which are impracticable of separation) by recipient and in total the aggregate of all payments made during the year where the aggregate of all such payments to a recipient was $25,000 or more including fees, retainers, commissions, gifts, contributions, assessments, bonuses, subscriptions, allowances for expenses or any other form of payments for services or as donations (except rents for property, taxes, utility services, traffic settlements, amounts paid for general services and licenses, accurals paid to trustees of pension and other employee benefit funds, and amounts paid for construction or maintenance of plant to persons other than affiliates) to any one corporation, institution, association, firm, partnership, committee, or person (not an employee of the respondent). Indicate by an asterisk in column (c) each item that includes payments for materials furnished incidental to the service performed. Payments to a recipient by two or more companies within a single system under a cost sharing or other joint arrangement shall be considered a single item for reporting in this schedule and shall be shown in the report of the principal company in the joint arrangement (as measured by gross operating revenues) with references thereto in the reports of the other system companies in the joint arrangement.
2. If more convenient, this schedule may be filled out for a group of companies considered as one system and shown only in the report of the principal company in the system, with references thereto in the reports of the other companies.

	Name of Recipient (a)	Nature of Service (b)	Amount of Payment Allocated to Oregon (c)
1	AGREE TECHNOLOGIES AND SOLUTIO	Energy Efficiency Services	$ 10,850
2	AKIN GUMP STRAUSS HAUER & FELD	Legal Services	2,008
3	ANDERSON BANDUCCI PLLC	Legal Services	10,487
4	APPLIED ENERGY GROUP	Management Services	2,193
5	BAKER BOTTS LLP	Legal Services	1,804
6	BARKER, ROSHOLT & SIMPSON LLP	Legal Services	16,662
7	BAYSWATER LLC	Legal Services	11,269
8	BROADRIDGE FINANCIAL SOLUTIONS	Management Services	2,114
9	CAMACK CONSULTING INC	Employee Benefit Services	1,841
10	CASE FORENSICS CORPORATION	Management Services	1,157
11	CGI TECHNOLOGIES AND SOLUTIONS	IT Services	8,177
12	CLEAREDGE PARTNERS INC	Management Services	3,342
13	COMPUNET, INC	IT Services	1,511
14	CORPORATE OFFICE INSTALLATIONS	Management Services	16,513
15	DAVIS WRIGHT TREMAINE LLP	Legal Services	65,086
16	DELOITTE TAX LLP	Management Services	1,605
17	E SOURCE, INC.	Training Consultants	1,412
18	ERGO RISK MANAGEMENT GROUP INC	Training Consultants	5,871
19	EVERGREEN CONSULTING GROUP, LL	Management Services	16,247
20	EXISTBI	Business Intelligence Support services	5,529
21	GIVENS PURSLEY LLP	Legal Services	6,381
22	H. W. LOCHNER, INC.	Enviromental Services	1,658
23	HAWLEY TROXELL ENNIS & HAWLEY	Legal Services	1,388
24	HONEYWELL INTERNATIONAL INC	Management Services	32,676
25	INDUSTRIAL HYGIENE RESOURCES,	Management Services	5,084
26	INTELLITECT	Management Services	5,200
27	ISS CORPORATE SERVICES, INC	Management Services	1,560
28	ITRON, INC.	Resource Management	9,843
29	MAINLINE INFORMATION SYSTEMS I	Management Services	6,257
30	MCDOWELL RACKNER & GIBSON PC	Legal Services	31,724
31	MIRANDE, MICHAEL	Legal Services	1,273
32	MOVESAFE INC	Training Consultants	9,229
33	NIELSEN GROUP INC, THE	IT Services	7,913
34	OXFORD GLOBAL RESOURCES INC	Management Services	11,033
35	PAINE HAMBLEN LLP	Legal Services	2,549
36	PERKINS COIE LLP	Legal Services	17,226
37	PRICEWATERHOUSE COOPERS LLP	Management Services	8,455
38	REED HARRIS ENVIRONMENTAL LTD	Environmental Services	1,500
39	REGULUS INTEGRATED SOLUTIONS	#VALUE!	3,690
40	REX BLACK CONSULTING SERVICES	IT Services	1,246
41	RIGHT SYSTEMS, INC	IT Services	1,627
42	RM ENERGY CONSULTING	Management Services	14,511
43	SHL US INC	Talent Services	2,199
44	STOEL RIVES LLP	Legal Services	6,164
45	SULLIVAN & CROMWELL	Legal Services	6,052
46	TATA AMERICA INTERNATIONAL COR	Management Services	71,911
47	TRINOOR LLC	HR Consulting	2,291
48	TUERI LLC	Management Services	6,268
49	UNIVERSITY OF IDAHO	Management Services	9,952
50	VAN NESS FELDMAN	Legal Services	20,008
51	WESTERN UNION FINANCIAL	Customer Billing Services	1,783
52			
	TOTAL		$ 494,326

A CENTURY OF SERVICE

2015
ANNUAL REPORT

IDACORP®

To Our Fellow Shareholders

Continuing the Legacy

Robert A. Tinstman

Darrel Anderson

We are proud to report that 2015 was another financially and operationally strong year for IDACORP and its primary subsidiary, Idaho Power. The year closed a chapter on our first century of business. As we look back at the strong foundation that ensured the success and longevity of the company, we also look forward to the challenges and opportunities that the next chapter provides as we continue on as an independent, integrated electric utility.

2015 marked IDACORP's eighth consecutive year of improved earnings. Idaho Power will share approximately $3 million with Idaho customers under our regulatory stipulation. This continued a trend of several years of sharing with customers, amounting to more than $120 million in total.

Looking back, the successes of 2015 are attributable to the execution of our business strategy and our focus on our clean, low-cost hydroelectric base, constructive regulatory activities, growth in customers and economic activity in Idaho Power's service area.

Looking ahead, Idaho Power estimates total capital expenditures of nearly $1.5 billion over the next five years. Noteworthy projects include the replacement of aging assets, upgrades to generation plants, a multi-year plan for replacement of underground cable, ongoing system upgrades and continued progress on permitting the Boardman to Hemingway and Gateway West 500-kilovolt transmission projects.

Our 17 hydroelectric dams on the Snake River and its tributaries are the crown jewels of our system. As recently highlighted in United Airlines' *Hemispheres* magazine, "We were green before green was the thing to be." Our hydro facilities are our legacy, providing a clean, reliable, flexible system at a low cost for our customers. These plants, together with three natural gas plants and three coal plants, all play important roles in providing electricity to our customers. Even removing the capacity generated by the 17 hydro plants we operate on the Snake River and its tributaries, 20.1 percent of the actual nameplate capacity on Idaho Power's system consisted of renewables in 2015.

A prudent regulatory strategy is another key to our success. We work collaboratively to help ensure timely cost recovery while keeping customer rates fair. We also are careful to approach other regulatory issues, such as renewable energy, in a thoughtful, strategic manner for the benefit of our shareholders and customers.

Idaho Power's century-old roots continue to grow in Idaho. To this day, electricity that is affordable and readily available is a major factor in our region's long-term economic growth. Our reliable and fair-priced energy is a key reason large companies like Chobani, Clif Bar and Amy's Kitchen have chosen to site facilities in — and bring jobs to — Idaho Power's service area.

You can't have power without people, and Idaho Power works to maximize our human resources. We embrace succession planning at all levels, resulting in a talented bench from which to choose our future leaders. Our leadership team has broad management experience and is skilled at controlling costs, optimizing our system and growing revenues. Our Board of Directors has the diverse collective background for successful oversight of policies, providing thoughtful and valuable counsel.

Idaho Power also continues to receive national media recognition for corporate excellence. In the September issue of *Public Utilities Fortnightly*, our company ranked number 11 of investor-owned utilities in the publication's list of the 40 best energy companies. That's up from 17th in the prior year and a substantial jump for the fourth year in a row. The Fortnightly 40 measures utilities' long-term performance and ranks them according to operating efficiency, asset utilization and financial leverage.

Enhancing shareholder value is top-of-mind for IDACORP. On September 17, our Board of Directors approved an 8.5 percent increase in the regular quarterly cash dividend on IDACORP's common stock, from $0.47 per share to $0.51 per share. IDACORP's Board of Directors has approved dividend increases in each of the last four years, representing a cumulative increase of 70 percent in IDACORP's quarterly dividend over that period.

Like any company that has been around for a century, Idaho Power has accomplished a lot. We've grown and adapted to many changes. We continue to find ways to optimize, help grow our local economy and embrace new opportunities. It's an exciting time to be in the energy business. We look forward to building on the strong foundation of the past 100 years as we work to produce long-term value for you, our shareowners.

Robert A. Tinstman
Chairman of the Board

Darrel Anderson
President and Chief Executive

2015 HIGHLIGHTS

Dollar Amounts in Thousands, Except Per Share Amounts	2015	2014	% Change
Total Operating Revenues	$1,270,289	$1,282,524	-1.0
IDACORP Net Income	$194,679	$193,480	0.6
Earnings Per Diluted Common Share	$3.87	$3.85	0.5
Dividends Declared Per Common Share	$1.92	$1.76	9.1
Total Assets	$6,023,314	$5,701,037	5.7
Number of Employees (full-time)	2,002	2,021	-0.9

A Century of Service

Idaho Power begins its second century with great opportunities. The company has the resources to deliver electricity to homes and businesses throughout its service area for the next decade, and we're already planning for 2025 and beyond.

Building the Future · 100 YEARS · Powering Generations · 1916 · 2016 · IDAHO POWER

OUR LEGACY

POWERING GENERATIONS

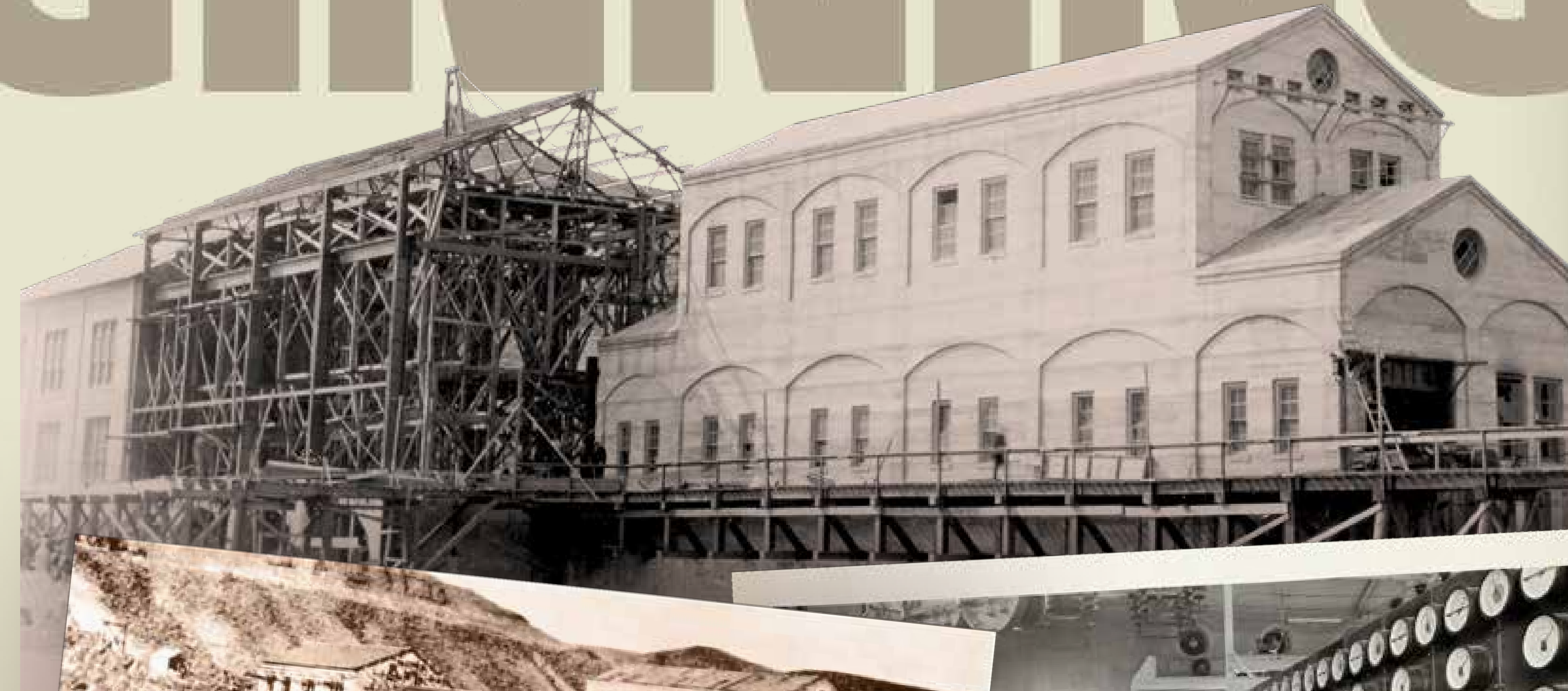
In 2016, we celebrate 100 years of service. Idaho Power was founded in 1916 when five companies combined. The new company harnessed the Snake River for hydroelectric power. We take pride in adoption of technology, care for natural resources and the relationships we have built with communities. The company's core values are integrity, safety and respect.

Our path to the centennial included hardships. We adapted and persevered to balance the interests of shareholders, customers and employees. We thank our employees for the company's success. Their dedication and commitment makes this celebration possible.

In the 1920s, Idaho Power's mobile crews visited farms and ranches and set pole after pole in places far away from the company's headquarters in Boise. By late that decade Idaho Power had 10,000 rural customers and had constructed more than 1,100 miles of rural transmission lines. But it took until the late 20th century to accomplish Idaho Power's ambitious goal of reaching every household in its service area.

THE BEGINNING

BUILDING POWER



In 1916, the company began with nine hydroelectric plants. Idaho Power spent the next 15 years investing in construction and growth projects to improve generating capacity and facilities from Pocatello in the east to Swan Falls in the west. Through these projects, the company formed close business partnerships with local industries, including mining, agriculture and manufacturing. These partnerships would last throughout the next 100 years.

As its facilities grew, Idaho Power's sales team presented the benefits of electricity to households in its service area by selling modern electric appliances directly to customers. Salesmen sold items like clothes washers, waffle irons and cooking ranges. These appliances promised Idaho housewives a new way of life. To serve the customers who bought these wares, the company started its rural electrification program. The program's goal was to bring power to even the most remote customers and make Idaho Power well-known in cities, towns, farms and ranches across its service area.

IDAHO POWER
A CITIZEN WHEREVER IT SERVES

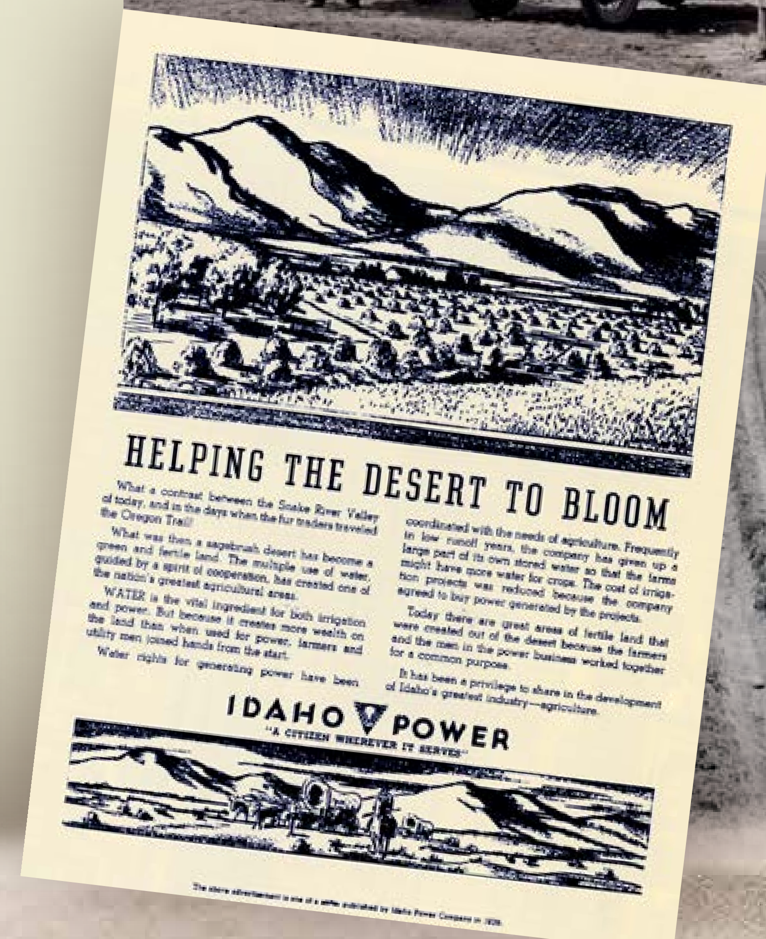
In 1916, Idaho Power's facilities generated only 20,340 kilowatts (kW) and served only 18,000 customers. But demand for electricity grew dramatically. To keep pace, the company upgraded its existing facilities and built several new ones. Using the power of the Snake River's many natural waterfalls was the key to the company's future.

DEPRESSION ERA

MAKING THE DESERT BLOOM

The Great Depression took Idaho Power and its customers on a bumpy ride. Idaho Power focused on balancing the needs of customers, employees and shareholders through dramatic changes. The company's biggest problem was finding ways to keep growing to meet electricity demand, which continued to increase in spite of hard times.

New dams and better transmission lines were the focus of plans for reliable generation, but the economic conditions and legal changes of the 1930s stalled much of the work. For example, the *Public Utility Holding Company Act of 1935* required Idaho Power to combine its service area into a cohesive geographic area. The decade had many silver linings — improvements to safety, an 8-hour work day and Idaho Power's pledge that it would be run by "the same local people, representing the territory served," and provide "the greatest possible service at the lowest possible cost, consistent with good service."



HELPING THE DESERT TO BLOOM

What a contrast between the Snake River Valley of today, and in the days when the fur traders traveled the Oregon Trail!

What was then a sagebrush desert has become a green and fertile land. The multiple use of water, guided by a spirit of cooperation, has created one of the nation's greatest agricultural areas.

WATER is the vital ingredient for both irrigation and power. But because it creates more wealth on the land than when used for power, farmers and utility men joined hands from the start.

Water rights for generating power have been coordinated with the needs of agriculture. Frequently in low runoff years, the company has given up a large part of its own stored water so that the farms might have more water for crops. The cost of irrigation projects was reduced because the company agreed to buy power generated by the projects.

Today there are great areas of fertile land that were created out of the desert because the farmers and the men in the power business worked together for a common purpose.

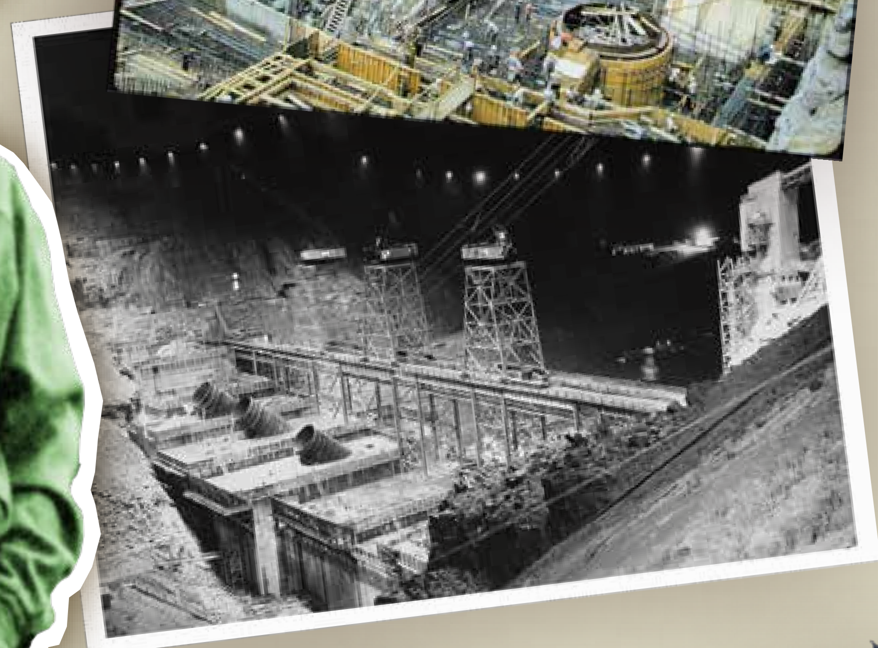
It has been a privilege to share in the development of Idaho's greatest industry—agriculture.

IDAHO POWER

"A CITIZEN WHEREVER IT SERVES"

COLD WAR ERA

HELLS CANYON



The 1960s began with Idaho Power adding the last two dams it would build on the Snake River — Oxbow and Hells Canyon. The Hells Canyon Complex exceeded existing demand because it was designed to meet the immediate energy demands of Cold War industry along with future needs. Once again, the company had to boost customer use. Idaho Power balanced these needs successfully. Increased pump irrigation, new manufacturing and new advances, such as air conditioning, pushed the company's overall energy sales from 1 billion to 6 billion kilowatt-hours between 1950 and 1966. During this era, Idaho Power also partnered with neighboring electric utilities to link several states through the construction of massive transmission lines.

This decade was a key moment in American history. Americans wanted the cheap power that made their lives easier. They also wanted Idaho Power to care for the land and rivers. To support this value of environmental responsibility, the federal government required Idaho Power to explore programs to reduce fish losses caused, in part, by its dams. Idaho Power's Environmental department expanded as it launched programs to achieve this goal.

Idaho Power President Thomas Roach (r) and Morrison-Knudsen President Harry Morrison were instrumental in the building of the Hells Canyon Complex, which comprises three dams: Brownlee, Oxbow and Hells Canyon.

After construction on Oxbow ended in 1961, Idaho Power's focus turned to its flagship dam, Hells Canyon. Everything about Hells Canyon was dramatic:

- Its size
- The number of workers who built it
- The amount of electricity it generated
- Its cost

21st CENTURY

ESSENTIAL SERVICES

IDACORP entered the 21st century with a bold mission to transition into an "essential services" company while remaining true to its commitment to responsibly provide reliable, affordable electricity for its growing number of customers. The strategy moved the company into broadband, financial services and energy marketing. The goal was to meet growing customer needs while diversifying the company's sources of income and bolstering shareholder revenue. The Western energy crisis of 2000 to 2001 prompted the company to re-evaluate this strategy. The result was a return to its core business, Idaho Power, and a renewed focus on present and future energy needs.

During the crisis, electrical systems across the West experienced brownouts and blackouts during periods of peak energy demand. Idaho Power avoided those shortages, and when the energy markets settled down, IDACORP decided to return to its roots with an "Electricity Plus" theme. This back-to-basics approach has paid dividends by helping develop a deeper understanding of what Idaho Power has provided for 100 years: reliable electricity, excellent customer service and community outreach. We are committed to safety, service and a vibrant corporate culture.

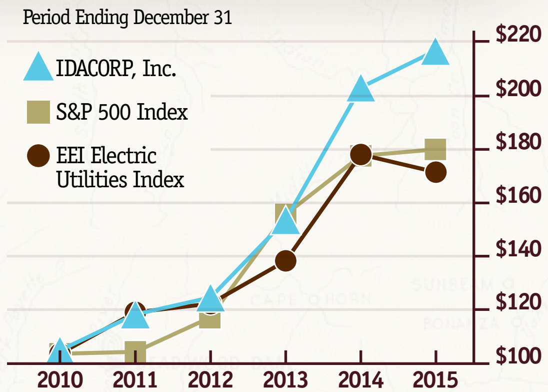
A Legacy of Financial Strength

IDACORP's focus remains on our clearly defined business strategy that positions us to deliver sound financial results. IDACORP general business revenue increased $28.8 million in 2015 compared with 2014. Annual earnings per share have grown over the last eight years.

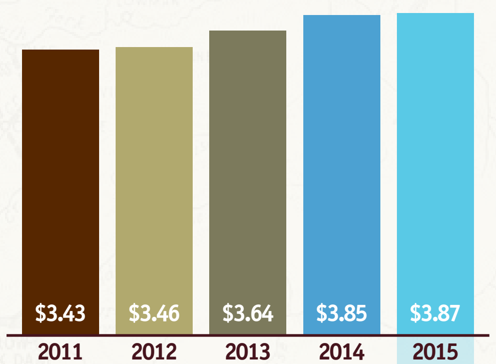
Idaho Power recorded no additional amortization of accumulated deferred investment tax credits, or ADITCs, in 2015 under the Idaho regulatory settlement stipulation, leaving $45 million of additional ADITCs available for future use.

Dividend Growth

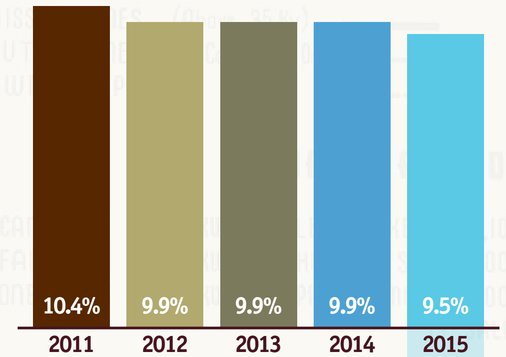
During 2015 IDACORP continued to make significant progress toward its target dividend payout ratio of between 50 and 60 percent of sustainable IDACORP earnings, which expands on progress made in previous years. From 2012 through 2016, IDACORP's Board of Directors has approved a collective 70 percent increase in the quarterly dividend, from $0.30 to $0.51 per share.



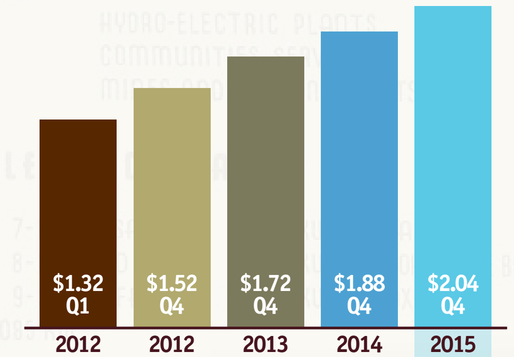
Comparison of Cumulative Total Return



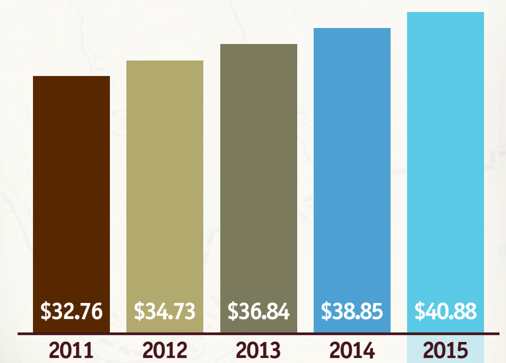
Diluted Earnings Per Share



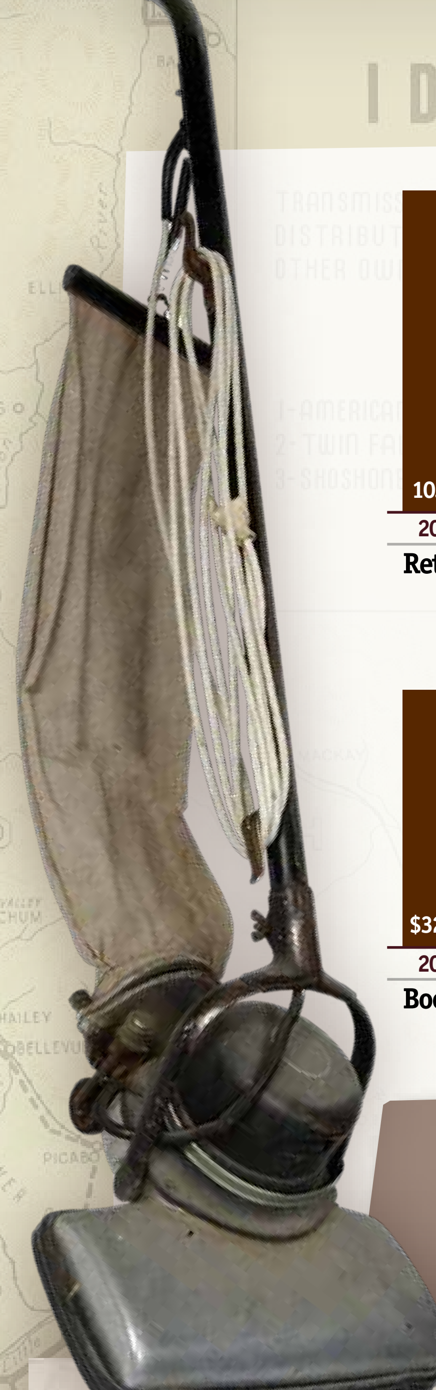
Return on Year-End Equity



Annualized Dividend Per Share



Book Value Per Share



Idaho Power President Thomas Roach (r) and Morrison-Knudsen President Harry Morrison signing the Brownlee and Oxbow construction contract in 1955.

Idaho Power partnered with appliance dealers who aimed to sell popular machines like washers and "hoovers." The company's sales team focused on increasing demand for new appliances and turning low-use customers into high-use consumers. The efforts worked.

1926, A copper washer for a silver dollar down.

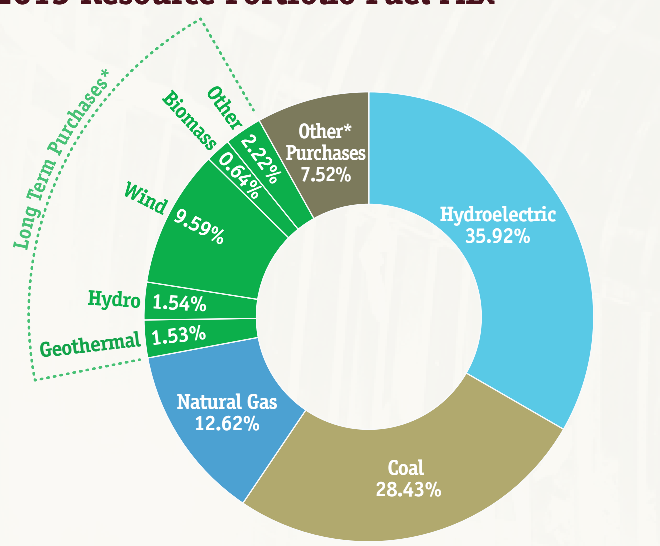
A Legacy of Responsible Resources and Planning

Generation Resources

Idaho Power's system is heavily weighted toward clean, renewable generation. The company began in 1916 as a solely hydro-based utility, and a century later, this resource remains the key to keeping our customers' electricity among the lowest-cost and cleanest in the country. The 17 hydroelectric projects on the Snake River and its tributaries are our least-cost generation resource, and provide about half of the electricity we deliver to customers in a normal water year.

At the three coal plants Idaho Power co-owns, generation decreased while natural gas-fired generation increased; low regional natural gas prices made running the company's three natural gas-fired plants more economical in 2015, further reducing our carbon footprint.

2015 Resource Portfolio Fuel Mix*



*Because Idaho Power sells (or does not own) the renewable energy certificates or "green tags" associated with certain projects in its resource portfolio, using the proceeds to benefit customers, we are not permitted to say the electricity from those projects is delivered to customers.

Renewable Energy and PURPA

In August, the Idaho Public Utilities Commission granted Idaho Power's request to reduce the length of new PURPA energy sales agreements from 20 years to two years. Idaho Power argued that the continued creation of 20-year term contracts placed undue risk on customers at a time when the company has sufficient resources to meet customer needs. The cost of existing long-term wind and solar energy contracts already runs into the billions of dollars.

As of Feb. 18, 2016, Idaho Power had 320 megawatts nameplate of solar capacity under contract and scheduled to begin production in 2016. If all of those solar resources come online, the percentage of hydro, wind, solar and other renewable generation capacity on Idaho Power's system would be greater than 60 percent of the total capacity by the end of this year.

Emissions Reductions

Idaho Power's thermal energy resources are among the nation's cleanest and getting cleaner. The company recently extended its commitment to further the reduction of carbon dioxide emissions intensity from its fleet.

The company has committed to reducing its average emissions intensity to 15 to 20 percent below 2005 levels for the 2010 to 2017 timeframe. Idaho Power achieved its goal to reduce average CO_2 emissions intensity by 10 to 15 percent below 2005 emissions for the period from 2010 through 2015, reducing emissions intensity by approximately 21 percent.

500-kilovolt Transmission Investments

The 300-mile Boardman to Hemingway 500-kilovolt (kV) transmission line was included in the preferred resource portfolio in Idaho Power's 2015 Integrated Resource Plan. Idaho Power expects the Bureau of Land Management (BLM) to issue a final Environmental Impact Statement (EIS) during 2016, and a Record of Decision in late 2016 or early 2017.

In the separate Oregon state permitting process, Idaho Power intends to finalize its amended preliminary application for a site certificate in 2016. Given the status of ongoing permitting activities, the in-service date for the line is expected to be in 2022 or beyond.

Gateway West is a 500-kV, 1,100-mile transmission project jointly proposed by Idaho Power and PacifiCorp.

In its November 2013 record of decision, the BLM identified final routing of eight of 10 segments of the project and deferred a decision on two segments to resolve routing concerns in those areas.

The BLM has initiated the supplemental EIS process for the two deferred segments, and that document is expected in spring 2016. The agency is expected to issue a record of decision on those segments later in 2016.

Technological advances in the utility industry were another sign of modern times. These advances changed the way Idaho Power conducted business. Idaho Power installed self-regulating transformers and began using cranes to load poles in the 1940s.

A Legacy of Thoughtful Regulatory Actions

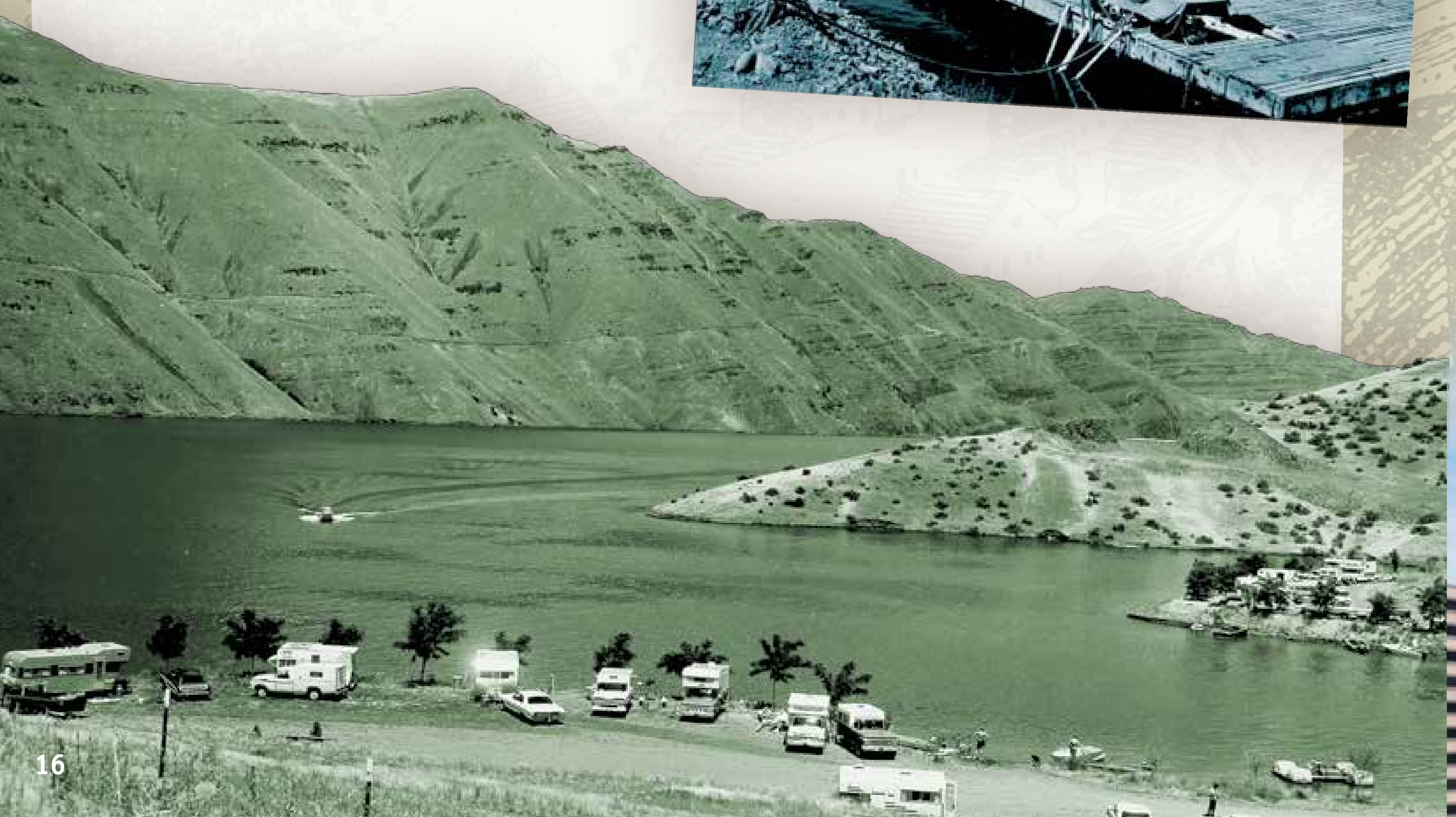
Idaho Power remains focused on advancing a purposeful regulatory strategy. The company has focused on timely recovery of costs through filings with the company's regulators, innovative regulatory mechanisms, and prudent management of expenses and investments. Idaho Power has a regulatory settlement stipulation in Idaho that remains in effect through 2019. That stipulation includes provisions for the accelerated amortization of ADITCs to help achieve a minimum 9.5 percent return on year-end equity in the Idaho jurisdiction.

Idaho Power's base rates were most recently reset in 2012. During 2016 Idaho Power will evaluate the timing of filing an application for a general rate change in Idaho or Oregon.

Regulatory Mechanisms

The Fixed Cost Adjustment (FCA) is designed to remove Idaho Power's financial disincentive to invest in energy efficiency programs by separating the recovery of fixed costs from the variable kilowatt-hour charge. In May 2015, the IPUC approved a settlement stipulation that modified the FCA mechanism by replacing weather-normalized sales with actual sales. The FCA mechanism modification, combined with lower sales per customer due to energy efficiency measures, provided a $12.7 million benefit to operating income in 2015 compared with 2014.

To address the volatility of power supply costs, Idaho Power's Power Cost Adjustment (PCA) mechanisms in the Idaho and Oregon jurisdictions allow Idaho Power to recover from or refund to customers most of the fluctuations in power supply costs. In May 2015, the IPUC approved a settlement stipulation intended to improve the accuracy of the PCA by replacing the existing load-based adjustment used for determining power cost deferrals with a similar sales-based adjustment.



& Fostering Growth

Idaho Power has been pursuing significant enhancements to its utility infrastructure in an effort to ensure an adequate supply of electricity, to provide service to new customers and to maintain system reliability.

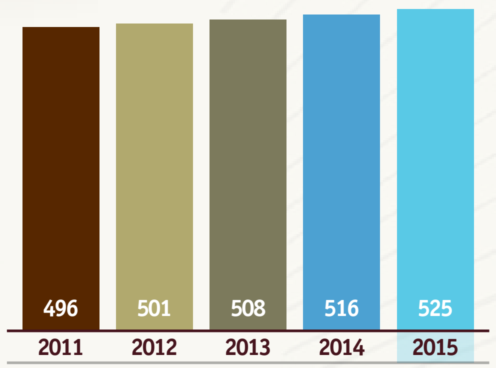
Customer Growth

In recent years, Idaho Power has seen growth in the number of customers in its service area, and the company expects that number to continue to increase in the foreseeable future. There was a 1.8 percent increase in customers in Idaho Power's service area from 2014 to 2015.

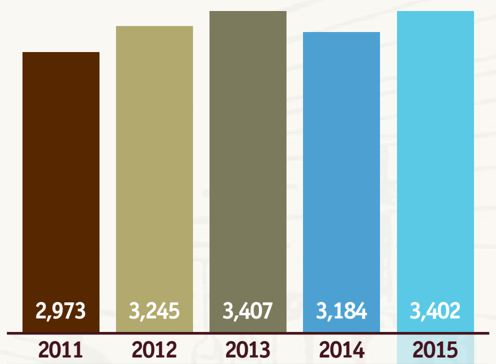
To help encourage that continued growth and highlight the company's service area, Idaho Power has in recent years launched efforts to promote business development and attract industrial and commercial customers to the service area.

Business Development Activity

Electricity that is affordable and available has been one of the major reasons for the region's long-term economic growth. National companies Chobani, Clif Bar and Amy's Kitchen are three recent customers to locate or expand operations in south central Idaho, and we are seeing others inquire often.



General Business Customers
(at Dec. 31, 2015) Thousands



Idaho Power System Peaks
in Megawatts

A Legacy of Service & Worth Your Investment

100 Years of Service

Idaho Power prides itself on the reliability of the electrical service we provide. But sometimes Mother Nature throws a very challenging situation our way. A range fire in August and a major snow storm in December showed our employees are at their very best when conditions are the worst.

During these two events Idaho Power restored power to thousands of people and replaced hundreds of poles and miles and miles of line. From the crews to the many folks behind the scenes, we were highly prepared and tightly coordinated when working to get power back on to our customers.

This kind of orchestrated effort, and the day-to-day of running our business, would not be possible without our dedicated employees, the more than 2,000 men and women who live the company's core values of integrity, safety and respect. It's the engaged and dedicated employees in all fields who are the backbone of Idaho Power's success.

For a hundred years Idaho Power has provided reliable, responsible, fair-priced energy services to our customers. It is our legacy. As we look back at the strong foundation that ensured the success and longevity of the company, we also look forward to the beginning of our next chapter as an independent, integrated electric utility.

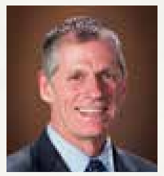
So what does that next chapter look like? It's keeping top-line revenue growth top-of-mind, along with optimization in all areas of the company, from identifying cost-saving measures to careful succession planning. It's continuing to keep a close eye on the horizon so we are prepared to embrace opportunities and successfully face any challenge. It's maintaining our unwavering commitment to our customers, employees and owners.

As the next chapter begins, we acknowledge the more than 2,000 safe, engaged and dedicated employees in all fields who continually contribute to the company's success. And we share our appreciation for you, our shareholders. We value your confidence in IDACORP and will continue working to make our company worthy of your investment now and in the future.

IDACORP and Idaho Power Board of Directors

(as of February 18, 2016)

Robert A. Tinstman*
(1999) Boise, Idaho
Director, Primoris Services Corp.; Home Federal Bancorp, Inc.; former Director of CNA Surety Corp.; and former President and Chief Executive Officer of Morrison-Knudsen Corporation.

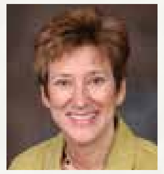


Darrel T. Anderson
(2013) Boise, Idaho
President and Chief Executive Officer of IDACORP, Inc. and Idaho Power.

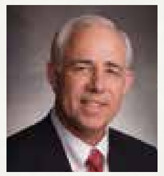
Thomas E. Carlile
(2014) Boise, Idaho
Former Chief Executive Officer of Boise Cascade Company; Director of Boise Cascade Company.

Richard J. Dahl
(2008) Kailua, Hawaii
Chairman of the Board, President and Chief Executive Officer of James Campbell Company, LLC; Director, DineEquity, Inc.; and former President and Chief Operating Officer of Dole Food Company.

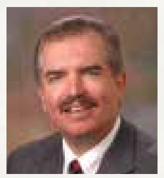
Ronald W. Jibson
(2013) North Salt Lake, Utah
President, Chief Executive Officer and Director, Questar Corporation; President and Chief Executive Officer of Wexpro Corporation; and President and Chief Executive Officer of Questar Gas Company; Director and Chairman of the Board of Questar Pipeline Company.



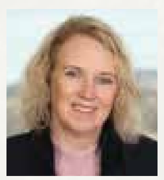
Judith A. Johansen
(2007) Scottsdale, Arizona
Director, Pacific Continental Corp., Pacific Continental Bank, Schnitzer Steel and Roseburg Forest Products; former President of Marylhurst University; former President and Chief Executive Officer of PacifiCorp; and former Chief Executive Officer and Administrator of the Bonneville Power Administration.



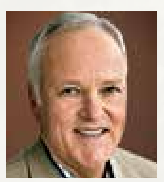
Dennis L. Johnson
(2013) Eagle, Idaho
President, Chief Executive Officer and Director of United Heritage Mutual Holding Company, United Heritage Financial Group, and United Heritage Life Insurance Company; Director of Cascade Bancorp.



J. LaMont Keen
(2004) Boise, Idaho
Former President and Chief Executive Officer, IDACORP, Inc. and Idaho Power Company; Director of Cascade Bancorp.



Christine King
(2006) Scottsdale, Arizona
Director and Executive Chair of QLogic Corp., Director of Cirrus Logic, Inc. and Skyworks Solutions, Inc.; former Director of Atheros Communications, Inc., Open-Silicon, Inc., and Standard Microsystems Corporation; former President and Chief Executive Officer of Standard Microsystems Corporation; and former President and Chief Executive Officer of AMI Semiconductor.



Richard J. Navarro
(2015) Boise, Idaho
Former Chief Financial Officer of Albertson's, LLC; former Senior Vice President and Controller at Albertson's, Inc.; former director of TitleOne Corporation and the Boise State University Foundation.

( ) year appointed or elected to the board
* Chairman of the Board

IDACORP and Idaho Power Officers

(as of February 18, 2016)

IDACORP and Idaho Power

Darrel T. Anderson (20)
President and Chief Executive Officer, IDACORP, Inc. and Idaho Power

Rex Blackburn (8)
Senior Vice President and General Counsel, IDACORP, Inc. and Idaho Power

Patrick A. Harrington (30)
Corporate Secretary, IDACORP, Inc. and Idaho Power

Steven R. Keen (33)
Senior Vice President, Chief Financial Officer and Treasurer, IDACORP, Inc. and Idaho Power

Jeffrey Malmen (8)
Vice President, Public Affairs, IDACORP, Inc. and Idaho Power

Daniel B. Minor (30)
Executive Vice President, IDACORP, Inc. and Idaho Power

Ken W. Petersen (17)
Vice President, Controller and Chief Accounting Officer, IDACORP, Inc. and Idaho Power

Lori D. Smith (32 – Retiring March 31, 2016)
Vice President and Chief Risk Officer, IDACORP, Inc. and Idaho Power

Idaho Power

Lisa A. Grow (28)
Senior Vice President, Operations

Jeffrey Glenn (Less than one year)
Vice President of Information Technology

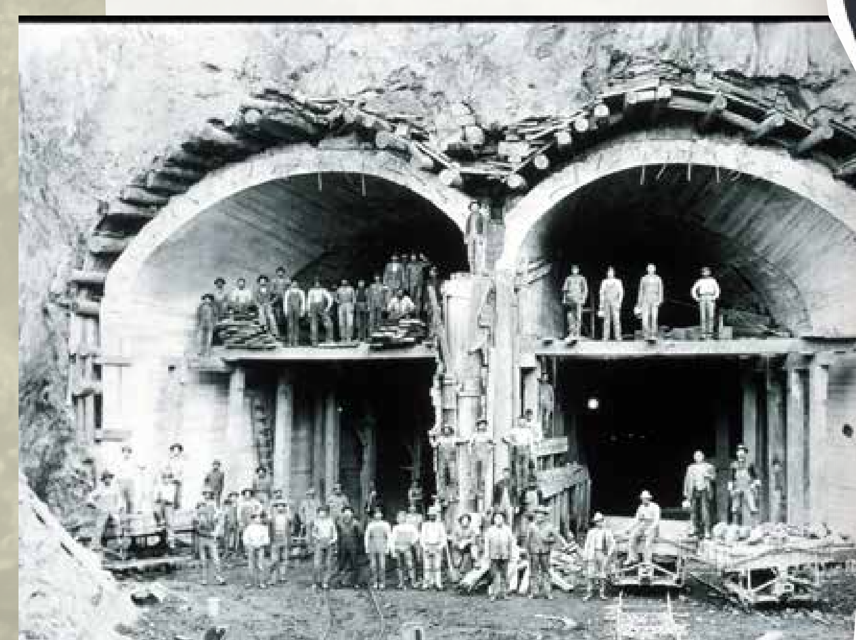
Lonnie Krawl (10)
Senior Vice President of Administrative Services and Chief Information Officer

Tessia Park (18)
Vice President of Power Supply

N. Vern Porter (26)
Vice President of Customer Operations

Gregory W. Said (35 – Retiring May 1, 2016)
Vice President, Regulatory Affairs

( ) Years of Service



Darrel Anderson

Dan Minor

Generation Facilities & Nameplate Capacities

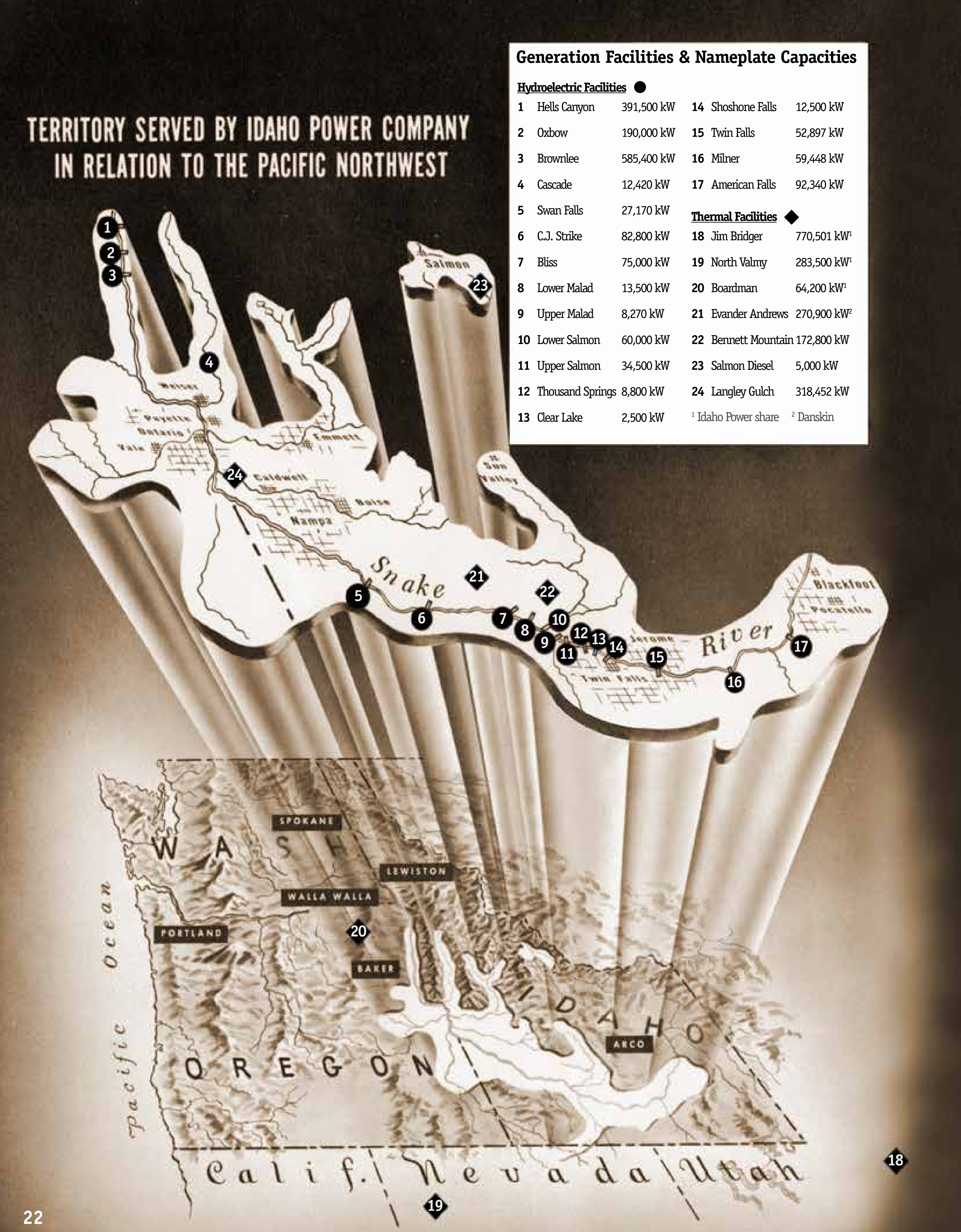
Hydroelectric Facilities ●

1	Hells Canyon	391,500 kW
2	Oxbow	190,000 kW
3	Brownlee	585,400 kW
4	Cascade	12,420 kW
5	Swan Falls	27,170 kW
6	C.J. Strike	82,800 kW
7	Bliss	75,000 kW
8	Lower Malad	13,500 kW
9	Upper Malad	8,270 kW
10	Lower Salmon	60,000 kW
11	Upper Salmon	34,500 kW
12	Thousand Springs	8,800 kW
13	Clear Lake	2,500 kW
14	Shoshone Falls	12,500 kW
15	Twin Falls	52,897 kW
16	Milner	59,448 kW
17	American Falls	92,340 kW

Thermal Facilities ◆

18	Jim Bridger	770,501 kW[1]
19	North Valmy	283,500 kW[1]
20	Boardman	64,200 kW[1]
21	Evander Andrews	270,900 kW[2]
22	Bennett Mountain	172,800 kW
23	Salmon Diesel	5,000 kW
24	Langley Gulch	318,452 kW

[1] Idaho Power share [2] Danskin



UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark One)

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2015

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from .... to ....

Commission File Number	Exact name of registrants as specified in their charters, address of principal executive offices, zip code and telephone number	IRS Employer Identification Number
1-14465	**IDACORP, Inc.**	82-0505802
1-3198	**Idaho Power Company**	82-0130980
	1221 W. Idaho Street	
	Boise, ID 83702-5627	
	(208) 388-2200	

State of incorporation: Idaho

SECURITIES REGISTERED PURSUANT TO SECTION 12(b) OF THE ACT:	Name of exchange on which registered
IDACORP, Inc.: Common Stock, without par value	New York Stock Exchange

SECURITIES REGISTERED PURSUANT TO SECTION 12(g) OF THE ACT:
Idaho Power Company: Preferred Stock

Indicate by check mark whether the registrants are well-known seasoned issuers, as defined in Rule 405 of the Securities Act.

IDACORP, Inc. Yes (X) No ( ) Idaho Power Company Yes ( ) No (X)

Indicate by check mark if the registrants are not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

IDACORP, Inc. Yes ( ) No (X) Idaho Power Company Yes ( ) No (X)

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. Yes (X) No ( )

Indicate by check mark whether the registrants have submitted electronically and posted on their corporate Web sites, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrants were required to submit and post such files).

IDACORP, Inc.	Yes	(X)	No	( )	Idaho Power Company	Yes	(X)	No	( )

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. (X)

Indicate by check mark whether the registrants are large accelerated filers, accelerated filers, non-accelerated filers, or smaller reporting companies.

IDACORP, Inc.:

Large accelerated filer (X) Accelerated filer ( ) Non-accelerated filer ( ) Smaller reporting company ( )

Idaho Power Company:

Large accelerated filer ( ) Accelerated filer ( ) Non-accelerated filer (X) Smaller reporting company ( )

Indicate by check mark whether the registrants are shell companies (as defined in Rule 12b-2 of the Act).

IDACORP, Inc.	Yes	( )	No	(X)	Idaho Power Company	Yes	( )	No	(X)

Aggregate market value of voting and non-voting common stock held by non-affiliates (June 30, 2015):

IDACORP, Inc.:	$ 2,798,093,674	Idaho Power Company:	None

Number of shares of common stock outstanding as of February 12, 2016:

IDACORP, Inc.:	50,297,581
Idaho Power Company:	39,150,812, all held by IDACORP, Inc.

Documents Incorporated by Reference:

Part III, Items 10 - 14	Portions of IDACORP, Inc.'s definitive proxy statement to be filed pursuant to Regulation 14A for the 2016 annual meeting of shareholders.

This combined Form 10-K represents separate filings by IDACORP, Inc. and Idaho Power Company. Information contained herein relating to an individual registrant is filed by that registrant on its own behalf. Idaho Power Company makes no representation as to the information relating to IDACORP, Inc.'s other operations.

Idaho Power Company meets the conditions set forth in General Instruction (I)(1)(a) and (b) of Form 10-K and is therefore filing this Form with the reduced disclosure format.

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* Except as indicated in Items 10, 12, and 14, IDACORP, Inc. information is incorporated by reference to IDACORP, Inc.'s definitive proxy statement for the 2016 annual meeting of shareholders.

COMMONLY USED TERMS

The following select abbreviations, terms, or acronyms are commonly used or found in multiple locations in this report:

ADITC	- Accumulated Deferred Investment Tax Credits
AFUDC	- Allowance for Funds Used During Construction
APCU	- Annual Power Cost Update
BCC	- Bridger Coal Company, a joint venture of IERCo
BLM	- U.S. Bureau of Land Management
BPA	- Bonneville Power Administration
CAA	- Clean Air Act
CO_2	- Carbon Dioxide
CWA	- Clean Water Act
EGUs	- Electric Utility Generating Units
EIS	- Environmental Impact Statement
EPA	- U.S. Environmental Protection Agency
EPS	- Earnings Per Share
ESA	- Endangered Species Act
FCA	- Fixed Cost Adjustment
FERC	- Federal Energy Regulatory Commission
FPA	- Federal Power Act
GAAP	- Generally Accepted Accounting Principles
GHG	- Greenhouse Gas
HCC	- Hells Canyon Complex
Ida-West	- Ida-West Energy Company, a subsidiary of IDACORP, Inc.
Idaho ROE	- Idaho-jurisdiction return on year-end equity
IERCo	- Idaho Energy Resources Co., a subsidiary of Idaho Power Company
IESCo	- IDACORP Energy Services Co., a subsidiary of IDACORP, Inc.
IFS	- IDACORP Financial Services, Inc., a subsidiary of IDACORP, Inc.
IPUC	- Idaho Public Utilities Commission
IRP	- Integrated Resource Plan
IRS	- U.S. Internal Revenue Service
kW	- Kilowatt
MATS	- Mercury and Air Toxics Standards
MD&A	- Management's Discussion and Analysis of Financial Condition and Results of Operations
MW	- Megawatt
MWh	- Megawatt-hour
NAAQS	- National Ambient Air Quality Standards
NMFS	- National Marine Fisheries Service
NOx	- Nitrogen Oxide
NSPS	- New Source Performance Standards
NSR/PSD	- New Source Review / Prevention of Significant Deterioration
O&M	- Operations and Maintenance
OATT	- Open Access Transmission Tariff
OPUC	- Public Utility Commission of Oregon
PCA	- Power Cost Adjustment
PCAM	- Oregon Power Cost Adjustment Mechanism
PURPA	- Public Utility Regulatory Policies Act of 1978
REC	- Renewable Energy Certificate
RPS	- Renewable Portfolio Standard
SEC	- U.S. Securities and Exchange Commission
SMSP	- Security Plan for Senior Management Employees
SO_2	- Sulfur Dioxide
USFWS	- U.S. Fish and Wildlife Service
VIEs	- Variable Interest Entities

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

In addition to the historical information contained in this report, this report contains (and oral communications made by IDACORP, Inc. and Idaho Power Company may contain) statements that relate to future events and expectations, such as statements regarding projected or future financial performance, cash flows, capital expenditures, dividends, capital structure or ratios, strategic goals, challenges, objectives, and plans for future operations. Such statements constitute forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Any statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions, or future events or performance, often, but not always, through the use of words or phrases such as "anticipates," "believes," "estimates," "expects," "intends," "potential," "plans," "predicts," "projects," "may result," "may continue," or similar expressions, are not statements of historical facts and may be forward-looking. Forward-looking statements are not guarantees of future performance and involve estimates, assumptions, risks, and uncertainties. Actual results, performance, or outcomes may differ materially from the results discussed in the statements. In addition to any assumptions and other factors and matters referred to specifically in connection with such forward-looking statements, factors that could cause actual results or outcomes to differ materially from those contained in forward-looking statements include those factors set forth in Part I, Item 1A - “Risk Factors” and Part II, Item 7 - “Management’s Discussion and Analysis of Financial Condition and Results of Operations" of this report, as well as in subsequent reports filed by IDACORP and Idaho Power with the Securities and Exchange Commission, and the following important factors:

- the effect of decisions by the Idaho and Oregon public utilities commissions, the Federal Energy Regulatory Commission, and other regulators that impact Idaho Power's ability to recover costs and earn a return;
- changes in residential, commercial, and industrial growth and demographic patterns within Idaho Power's service area and the loss or change in the business of significant customers, and their associated impacts on loads and load growth, and the availability of regulatory mechanisms that allow for timely cost recovery in the event of those changes;
- the impacts of economic conditions, including the potential for changes in customer demand for electricity, revenue from sales of excess power, financial soundness of counterparties and suppliers, and the collection of receivables;
- unseasonable or severe weather conditions, wildfires, drought, and other natural phenomena and natural disasters, which affect customer demand, hydroelectric generation levels, repair costs, and the availability and cost of fuel for generation plants or purchased power to serve customers;
- advancement of technologies that reduce loads or reduce the need for Idaho Power's generation or sale of electric power;
- adoption of, changes in, and costs of compliance with laws, regulations, and policies relating to the environment, natural resources, and threatened and endangered species, and the ability to recover increased costs through rates;
- variable hydrological conditions and over-appropriation of surface and groundwater in the Snake River Basin, which may impact the amount of power generated by Idaho Power's hydroelectric facilities;
- the ability to purchase fuel, power, and transmission capacity under reasonable terms, particularly in the event of unanticipated power demands, lack of physical availability, transportation constraints, or a credit downgrade;
- accidents, fires (either at or caused by Idaho Power facilities), explosions, and mechanical breakdowns that may occur while operating and maintaining an electric system, which can cause unplanned outages, reduce generating output, damage the companies’ assets, operations, or reputation, subject the companies to third-party claims for property damage, personal injury, or loss of life, or result in the imposition of civil, criminal, and regulatory fines and penalties;
- the increased costs and operational challenges associated with purchasing and integrating intermittent renewable energy sources into Idaho Power's resource portfolio;
- administration of reliability, security, and other requirements for system infrastructure required by the Federal Energy Regulatory Commission and other regulatory authorities, which could result in penalties and increase costs;
- disruptions or outages of Idaho Power's generation or transmission systems or of any interconnected transmission system;
- the ability to obtain debt and equity financing or refinance existing debt when necessary and on favorable terms, which can be affected by factors such as credit ratings, volatility in the financial markets, interest rate fluctuations, decisions by the Idaho or Oregon public utility commissions, and the companies' past or projected financial performance;
- reductions in credit ratings, which could adversely impact access to capital markets and would require the posting of additional collateral to counterparties pursuant to credit and contractual arrangements;
- the ability to enter into financial and physical commodity hedges with creditworthy counterparties to manage price and commodity risk, and the failure of any such risk management and hedging strategies to work as intended;

- changes in actuarial assumptions, changes in interest rates, and the return on plan assets for pension and other post-retirement plans, which can affect future pension and other postretirement plan funding obligations, costs, and liabilities;
- the ability to continue to pay dividends based on financial performance, and in light of contractual covenants and restrictions and regulatory limitations;
- changes in tax laws or related regulations or new interpretations of applicable laws by federal, state, or local taxing jurisdictions, the availability of tax credits, and the tax rates payable by IDACORP shareholders on common stock dividends;
- employee workforce factors, including the operational and financial costs of unionization or the attempt to unionize all or part of the companies' workforce, the impact of an aging workforce and retirements, the cost and ability to retain skilled workers, and the ability to adjust the labor cost structure when necessary;
- failure to comply with state and federal laws, policies, and regulations, including new interpretations and enforcement initiatives by regulatory and oversight bodies, which may result in penalties and fines and increase the cost of compliance, the nature and extent of investigations and audits, and the cost of remediation;
- the inability to obtain or cost of obtaining and complying with required governmental permits and approvals, licenses, rights-of-way, and siting for transmission and generation projects and hydroelectric facilities;
- the cost and outcome of litigation, dispute resolution, and regulatory proceedings, and the ability to recover those costs or the costs of operational changes through insurance or rates, or from third parties;
- the failure of information systems or the failure to secure data, failure to comply with privacy laws, security breaches, or the direct or indirect effect on the companies' business or operations resulting from cyber attacks, terrorist incidents or the threat of terrorist incidents, and acts of war;
- unusual or unanticipated changes in normal business operations, including unusual maintenance or repairs, or the failure to successfully implement new technology solutions; and
- adoption of or changes in accounting policies and principles, changes in accounting estimates, and new Securities and Exchange Commission or New York Stock Exchange requirements, or new interpretations of existing requirements.

Any forward-looking statement speaks only as of the date on which such statement is made. New factors emerge from time to time and it is not possible for management to predict all such factors, nor can it assess the impact of any such factor on the business or the extent to which any factor, or combination of factors, may cause results to differ materially from those contained in any forward-looking statement. IDACORP and Idaho Power disclaim any obligation to update publicly any forward-looking information, whether in response to new information, future events, or otherwise, except as required by applicable law.

PART I
ITEM 1. BUSINESS

OVERVIEW

Background

IDACORP, Inc. (IDACORP) is a holding company incorporated in 1998 under the laws of the state of Idaho. Its principal operating subsidiary is Idaho Power Company (Idaho Power). IDACORP is subject to the provisions of the Public Utility Holding Company Act of 2005, which provides the Federal Energy Regulatory Commission (FERC) and state utility regulatory commissions with access to books and records and imposes record retention and reporting requirements on IDACORP.

Idaho Power was incorporated under the laws of the state of Idaho in 1989 as the successor to a Maine corporation that was organized in 1915 and began operations in 1916. Idaho Power is an electric utility engaged in the generation, transmission, distribution, sale, and purchase of electric energy and capacity and is regulated by the state regulatory commissions of Idaho and Oregon and by the FERC. 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. Idaho Power's utility operations constitute nearly all of IDACORP's current business operations and are IDACORP's only reportable business segment. Segment financial information is presented in Note 17 – "Segment Information" to the consolidated financial statements included in this report. As of December 31, 2015, IDACORP had 2,002 full-time employees, 1,993 of whom were employed by Idaho Power, and 21 part-time employees, 19 of whom were employed by Idaho Power.

IDACORP's other subsidiaries include IDACORP Financial Services, Inc. (IFS), an investor in affordable housing and other real estate investments; Ida-West Energy Company (Ida-West), an operator of small hydroelectric generation projects that satisfy the requirements of the Public Utility Regulatory Policies Act of 1978 (PURPA); and IDACORP Energy Services Co. (IESCo), the successor to IDACORP Energy L.P., a marketer of energy commodities that wound down operations in 2003.

IDACORP's and Idaho Power's principal executive offices are located at 1221 W. Idaho Street, Boise, Idaho 83702, and the telephone number is (208) 388-2200.

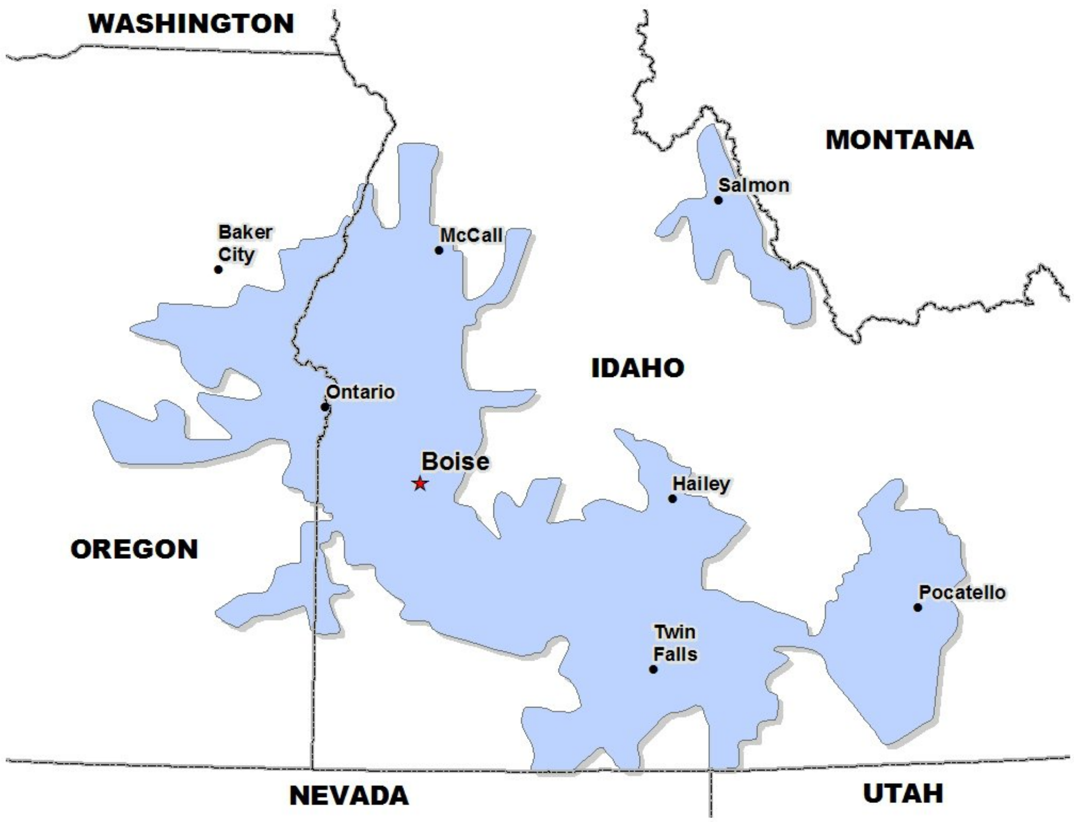
Available Information

IDACORP and Idaho Power make available free of charge on their websites their Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and all amendments to these reports filed or furnished pursuant to Section 13(a) or 15(d) of the U.S. Securities Exchange Act of 1934 as soon as reasonably practicable after the reports are electronically filed with or furnished to the U.S. Securities and Exchange Commission (SEC). IDACORP's website is *www.idacorpinc.com* and Idaho Power's website is *www.idahopower.com*. The contents of these websites are not part of this Annual Report on Form 10-K. Reports, proxy and information statements, and other information regarding IDACORP and Idaho Power may also be obtained directly from the SEC's website, *www.sec.gov*, or from the SEC's Public Reference Room at 100 F Street, NE, Washington, D.C. 20549.

UTILITY OPERATIONS

Background

Idaho Power provided electric utility service to approximately 525,000 general business customers in southern Idaho and eastern Oregon as of December 31, 2015. Over 436,000 of these customers are residential. Idaho Power's principal commercial and industrial customers are involved in food processing, electronics and general manufacturing, agriculture, health care, and winter recreation. Idaho Power holds franchises, typically in the form of right-of-way arrangements, in 71 cities in Idaho and 9 cities in Oregon and holds certificates from the respective public utility regulatory authorities to serve all or a portion of 25 counties in Idaho and 3 counties in Oregon. Idaho Power's service area is shaded in the illustration on the following page and covers approximately 24,000 square miles with an estimated population of one million.



Idaho Power is under the jurisdiction (as to rates, service, accounting, and other general matters of utility operation) of the Idaho Public Utilities Commission (IPUC), the Public Utility Commission of Oregon (OPUC), and the FERC. The IPUC and OPUC determine the rates that Idaho Power is authorized to charge to its general business customers. Idaho Power is also under the regulatory jurisdiction of the IPUC, the OPUC, and the Public Service Commission of Wyoming as to the issuance of debt and equity securities. As a public utility under the Federal Power Act, Idaho Power has authority to charge market-based rates for wholesale energy sales under its FERC tariff and to provide transmission services under its open access transmission tariff (OATT). Additionally, the FERC has jurisdiction over Idaho Power's sales of transmission capacity and wholesale electricity, hydroelectric project relicensing, and system reliability, among other items.

Regulatory Accounting

Idaho Power is subject to accounting principles generally accepted in the United States of America, with the impacts of rate regulation reflected in its financial statements. These principles sometimes result 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 or accrued 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. Idaho Power records regulatory assets or liabilities if it is probable that they will be reflected in future prices, based on regulatory orders or other available evidence.

Business Strategy

IDACORP's business strategy emphasizes Idaho Power as IDACORP's core business, as Idaho Power's utility operations are the primary driver of IDACORP's operating results. Idaho Power's three-part strategy can be summarized as follows:

- ***Responsible Planning***: Idaho Power's planning process is intended to ensure adequate generation, transmission, and distribution resources to meet anticipated population growth and increasing electricity demand. This planning process integrates Idaho Power's regulatory strategy and financial planning, including the consideration of regional economic development in the communities Idaho Power serves.

- ***Responsible Development and Protection of Resources***: Idaho Power's business strategy includes the development and protection of generation, transmission, distribution, and associated infrastructure, and stewardship of the natural resources upon which Idaho Power and the communities it serves depend. Additionally, the strategy considers workforce planning and employee development and retention related to these strategic elements.
- ***Responsible Energy Use***: Idaho Power's business strategy includes energy efficiency and demand response programs and preparation for potential carbon and renewable portfolio standards legislation. The strategy also includes targeted reductions relating to carbon emission intensity and public reporting of these reductions, as well as operating Idaho Power's system in a manner that extracts additional value through changes in fuel mix and generation.

Idaho Power's business strategy seeks to balance the interests of owners, customers, employees, and other stakeholders while maintaining the company's financial stability and flexibility. Idaho Power has further refined its three-part business strategy to include three core focuses for 2016—improving its core business, growing revenues, and enhancing the brand and positioning the company for the future. IDACORP continues to focus on its core business and its goal of generating returns for its shareholders and long-term shareholder value.

Rates and Revenues

Idaho Power generates revenue primarily through the sale of electricity to retail and wholesale customers and the provision of transmission service. The prices that the IPUC, the OPUC, and the FERC authorize Idaho Power to charge for the electric power and services Idaho Power sells are a critical factor in determining IDACORP's and Idaho Power's results of operations and financial condition. In addition to the discussion below, for more information on Idaho Power's regulatory framework and rate regulation, see the "Regulatory Matters" section of Part II, Item 7 – "Management's Discussion and Analysis of Financial Condition and Results of Operations" (MD&A) and Note 3 – "Regulatory Matters" to the consolidated financial statements included in this report.

Retail Rates**:** Idaho Power periodically evaluates the need to request changes to its retail electricity price structure to cover its operating costs and to seek to earn a return on its investments. Idaho Power uses general rate cases, power cost adjustment (PCA) mechanisms, a fixed cost adjustment (FCA) mechanism, balancing accounts and tariff riders, and subject-specific filings to recover its costs of providing service and to earn a return on investment. Retail prices are generally determined through formal ratemaking proceedings that are conducted under established procedures and schedules before the issuance of a final order. Participants in these proceedings include Idaho Power, the staffs of the IPUC or OPUC, and other interested parties. The IPUC and OPUC are charged with ensuring that the prices and terms of service are fair, are non-discriminatory, and provide Idaho Power an opportunity to recover its prudently incurred or allowable costs and expenditures and earn a reasonable return on investment. The ability to request rate changes does not, however, ensure that Idaho Power will recover all of its costs or earn a specified rate of return, or that its costs will be recovered in advance of or at the same time as the costs are incurred.

In addition to general rate case filings, ratemaking proceedings can involve charges or credits related to specific costs, programs, or activities, as well as the recovery or refund of amounts recorded under specific authorization from the IPUC or OPUC but deferred for recovery or refund. Deferred amounts are generally collected from or refunded to retail customers through the use of base rates or supplemental tariffs. Outside of base rates, three of the most significant mechanisms for recovery of costs are the PCA mechanisms, FCA mechanism, and energy efficiency rider. The Idaho and Oregon PCA mechanisms are intended to address the volatility of power supply costs and provide for annual adjustments to the rates charged to retail customers by allowing partial recovery of the difference between net power supply costs included in base rates and actual net power supply costs incurred by Idaho Power. The 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 for certain Idaho customer classes and linking it instead to a set amount per customer. Separately, Idaho Power collects most of its energy efficiency program costs through an energy efficiency rider on customer bills.

Wholesale Markets**:** As a public utility subject to the provisions of Part II of the Federal Power Act (FPA), Idaho Power has authority to charge market-based rates for wholesale energy sales under its FERC tariff and to provide transmission services under its OATT. Idaho Power's OATT transmission rate is revised each year based primarily on financial and operational data Idaho Power files annually with the FERC in its Form 1. The Energy Policy Act of 2005 granted the FERC increased statutory authority to implement mandatory transmission and network reliability standards, as well as enhanced oversight of power and transmission markets, including protection against market manipulation. These mandatory transmission and reliability standards were developed by the North American Electric Reliability Corporation (NERC) and the Western Electricity Coordinating Council (WECC), which have responsibility for compliance and enforcement of transmission and reliability standards.

Idaho Power participates in the wholesale energy markets by purchasing power to help meet load demands and selling power that is in excess of load demands. Idaho Power's market activities are guided by a risk management policy and frequently updated operating plans. These operating plans are impacted by factors such as customer demand for power, market prices, generating costs, transmission constraints, and availability of generating resources. Some of Idaho Power's 17 hydroelectric generation facilities are operated to optimize the water that is available by choosing when to run hydroelectric generation units and when to store water in reservoirs. Idaho Power at times operates these and its other generation facilities to take advantage of market opportunities. These decisions affect the timing and volumes of market purchases and market sales. Even in below-normal water years, there are opportunities to vary water usage to capture wholesale marketplace economic benefits, maximize generation unit efficiency and meet peak loads. Compliance factors such as allowable river stage elevation changes and flood control requirements also influence these generation dispatch decisions. Idaho Power's off-system sales revenues depend largely on the availability of generation resources above the amount necessary to serve customer loads as well as adequate market power prices at the time when those resources are available. When either factor is low, off-system sales revenue is reduced.

Energy Sales: Weather, seasonal customer demand, and economic conditions all impact the amount of electricity that Idaho Power sells as well as the costs it incurs to provide that electricity. Idaho Power's utility revenues are not earned, and associated expenses are not incurred, evenly during the year. Idaho Power’s retail energy sales typically peak during the summer irrigation and cooling season, with a lower peak in the winter. Extreme temperatures increase sales to customers who use electricity for cooling and heating, and moderate temperatures decrease sales. Increased precipitation levels during the agricultural growing season reduce electricity sales to customers who use electricity to operate irrigation pumps. The table that follows presents Idaho Power’s revenues and sales volumes for the last three years, classified by customer type. Approximately 95 percent of Idaho Power’s general business revenue originates from customers located in Idaho, with the remainder originating from customers located in Oregon. Idaho Power’s operations, including information on energy sales, are discussed further in Part II, Item 7 - MD&A - "Results of Operations - Utility Operations.”

	Year Ended December 31,		
	2015	**2014**	**2013**
General business revenues (thousands of dollars)			
Residential	$ 512,068	$ 500,195	$ 513,914
Commercial	306,178	299,462	281,009
Industrial	182,254	182,675	165,941
Irrigation	164,403	158,654	159,242
Provision for rate refund for sharing mechanism	(3,159)	(7,999)	(7,602)
Deferred revenue related to Hells Canyon Complex relicensing AFUDC	(10,706)	(10,706)	(10,776)
Total general business revenues	1,151,038	1,122,281	1,101,728
Off-system sales	30,887	77,165	54,473
Other	85,580	79,205	86,897
Total revenues	$ 1,267,505	$ 1,278,651	$ 1,243,098
Energy sales (thousands of MWh)			
Residential	4,977	4,965	5,365
Commercial	4,045	3,944	3,975
Industrial	3,196	3,217	3,182
Irrigation	2,047	1,966	2,097
Total general business	14,265	14,092	14,619
Off-system sales	1,254	2,220	1,683
Total	15,519	16,312	16,302

Competition: Idaho Power's electric utility business has historically been recognized as a natural monopoly. Idaho Power's rates for retail electric services are generally determined on a “cost of service” basis. Rates are designed to provide, after recovery of allowable operating expenses including depreciation on capital investments, an opportunity for Idaho Power to earn a reasonable return on investment as authorized by regulators. However, alternative methods of generation, including customer-owned solar and other forms of distributed generation, compete with Idaho Power for sales to existing customers. Also, non-utility businesses are developing new technologies and services to help energy consumers manage energy in new ways that could alter demand for Idaho Power's electric energy. Idaho Power also competes with fuel distribution companies in serving the energy needs of customers for space heating, water heating, and appliances.

Idaho Power also participates in the wholesale energy markets and in the electric transmission markets. Generally, these wholesale markets are regulated by the FERC, which requires electric utilities to transmit power to or for wholesale purchasers and sellers and make available, on a non-discriminatory basis, transmission capacity for the purpose of providing these services.

In return for agreeing to provide service to all customers within a defined service area, electric utilities are typically provided with an exclusive right to provide service in that service area. However, certain prescribed areas within Idaho Power's service area, such as municipalities or Native American Tribal reservations, may elect not to take service from Idaho Power and instead operate as a municipal electric utility or otherwise as a separate entity. In such cases, the entity would be required to purchase or otherwise obtain rights (such as by contract) to Idaho Power's distribution infrastructure within the municipal or other designated area. Idaho Power would have no responsibility for providing electric service to the municipal or separate entity, absent Idaho Power's voluntary execution of an agreement to provide that service. Separately, the Shoshone-Bannock Tribes, located in southeastern Idaho, have recently taken steps toward the adoption of a separate utility code applicable to electric utilities operating within the Shoshone-Bannock Tribal Reservation (Reservation). The proposed tribal utility code, if adopted, could ultimately lead to Idaho Power's cessation of its historical provision of service to the Reservation and could result in either no or a limited electric service relationship with the Reservation, or could result solely in Idaho Power's sale of power to the Reservation pursuant to a power purchase agreement. Idaho Power estimates that the average load for the Reservation over the prior five years is approximately 14 MW.

Power Supply

Overview: Idaho Power primarily relies on company-owned hydroelectric, coal-fired, and gas-fired generation facilities and long-term power purchase agreements to supply the energy needed to serve customers. Market purchases and sales are used to supplement Idaho Power's generation and balance supply and demand throughout the year. Idaho Power's generating plants and their capacities are listed in Part I, Item 2 - "Properties."

Weather, load demand, supply constraints, economic conditions, and availability of generation resources impact power supply costs. Idaho Power's annual hydroelectric generation varies depending on water conditions in the Snake River Basin. Drought conditions and increased peak load demand cause a greater reliance on potentially more expensive energy sources to meet load requirements. Conversely, favorable hydroelectric generation conditions increase production at Idaho Power's hydroelectric generating facilities and reduce the need for thermal generation and wholesale market purchased power. Economic conditions and governmental regulations can affect the market price of natural gas and coal, which may impact fuel expense and market prices for purchased power. Idaho Power's PCA mechanisms mitigate in large part the potentially adverse financial statement impacts of volatile fuel and power costs.

Idaho Power's system is dual peaking, with the larger peak demand occurring in the summer. The all-time system peak demand was 3,407 Megawatts (MW), set on July 2, 2013, at which time Idaho Power had deployed 30 MW of demand response programs to mitigate the load demand. The all-time winter peak demand was 2,527 MW, set on December 10, 2009. Idaho Power's peak demand during 2015 was 3,402 MW, the magnitude of which was diminished by the deployment of 60 MW of demand response programs during the peak load period. During these and other similarly heavy load periods Idaho Power's system is fully committed to serve load and meet required operating reserves. The table that follows shows Idaho Power's total power supply for the last three years.

	MWh			Percent of Total Generation		
	2015	2014	2013	2015	2014	2013
	(thousands of MWh)					
Hydroelectric plants	5,910	6,170	5,656	47%	47%	42%
Coal-fired plants	4,676	5,851	6,327	37%	44%	47%
Natural gas fired plants	2,076	1,175	1,576	16%	9%	11%
Total system generation	12,662	13,196	13,559	100%	100%	100%
Purchased power - cogeneration and small power production	2,008	2,286	2,127			
Purchased power - other	1,784	1,867	1,775			
Total purchased power	3,792	4,153	3,902			
Total power supply	16,454	17,349	17,461			

***Hydroelectric Generation*:** Idaho Power operates 17 hydroelectric projects located on the Snake River and its tributaries. Together, these hydroelectric facilities provide a total nameplate capacity of 1,709 MW and annual generation of approximately 8.5 million Megawatt-hours (MWh) under median water conditions. The amount of water available for hydroelectric power generation depends on several factors—the amount of snow pack in the mountains upstream of Idaho Power's hydroelectric facilities, upstream reservoir storage, springtime precipitation and temperatures, main river and tributary base flows, the condition of the Eastern Snake Plain Aquifer and its spring flow impact, summer time irrigation withdrawals and returns, and upstream reservoir regulation. Idaho Power actively participates in collaborative work groups focused on water management issues in the Snake River Basin, with the goal of preserving the long-term availability of water for use at Idaho Power's hydroelectric projects on the Snake River.

During low water years, when stream flows into Idaho Power's hydroelectric projects are reduced, Idaho Power's hydroelectric generation is reduced. The result is a greater reliance on other generation resources and power purchases. In 2014, significantly low upstream carryover water storage hindered the impact of the runoff of near-normal snow accumulation, resulting in generation of 6.2 million MWh. In 2015, below-normal snow accumulation resulted in a lower than median hydro production of 5.9 million MWh. The Northwest River Forecast Center of the National Oceanic Atmospheric Administration reported that the 2015 April through July inflow volume into Brownlee Reservoir (the uppermost reservoir of Idaho Power's Hells Canyon Complex) was only 46 percent of normal. By comparison, April through July Brownlee Reservoir inflow was 63 percent of normal in 2014. For 2016, Idaho Power estimates annual generation from its hydroelectric facilities of between 6.0 million MWh and 8.0 million MWh.

Idaho Power obtains licenses for its hydroelectric projects from the FERC, similar to other utilities that operate nonfederal hydroelectric projects on qualified waterways. The licensing process includes an extensive public review process and involves numerous natural resource and environmental agencies. The licenses last from 30 to 50 years depending on the size, complexity, and cost of the project. Idaho Power is actively pursuing the relicensing of the Hells Canyon Complex project, its largest hydroelectric generation source. Idaho Power also has three Oregon licenses under the Oregon Hydroelectric Act, which applies to Idaho Power's Brownlee, Oxbow, and Hells Canyon facilities. For further information on relicensing activities see Part II, Item 7 – MD&A – "Regulatory Matters – Relicensing of Hydroelectric Projects."

Idaho Power is subject to the provisions of the FPA as a "public utility" and as a "licensee" by virtue of its hydroelectric operations. As a licensee under Part I of the FPA, Idaho Power and its licensed hydroelectric projects are subject to conditions described in the FPA and related FERC regulations. These conditions and regulations include, among other items, provisions relating to condemnation of a project upon payment of just compensation, amortization of project investment from excess project earnings, and possible takeover of a project after expiration of its license upon payment of net investment and severance damages.

***Coal-Fired Generation*:** Idaho Power co-owns the following coal-fired power plants:

- Jim Bridger located in Wyoming, in which Idaho Power has a one-third interest;
- North Valmy located in Nevada, in which Idaho Power has a 50 percent interest; and
- Boardman located in Oregon, in which Idaho Power has a 10 percent interest.

Bridger Coal Company (BCC) supplies coal to the Jim Bridger power plant. Idaho Power owns a one-third interest in BCC and PacifiCorp owns a two-third interest in BCC and is the operator of the Bridger Coal Mine. The mine operates under a long-term sales agreement that provides for delivery of coal over a 51-year period ending in 2024 from surface and underground sources. Idaho Power believes that BCC has sufficient reserves to provide coal deliveries for at least the term of the sales agreement. Idaho Power also has a coal supply contract providing for annual deliveries of coal through 2017 from the Black Butte Coal Company's Black Butte mine located near the Jim Bridger plant. This contract supplements the BCC deliveries and provides another coal supply to operate the Jim Bridger plant. The Jim Bridger plant's rail load-in facility and unit coal train, while limited, provides the opportunity to access other fuel supplies for tonnage requirements above established contract minimums.

NV Energy is the operator of the North Valmy power plant. NV Energy and Idaho Power have contracts with a coal supplier through 2016. Idaho Power's share of these contracts, together with the existing coal inventory at the North Valmy plant, are expected to meet Idaho Power's projected coal requirements at the plant through 2017. Idaho Power expects to be able to obtain future coal requirements through similar contracts.

Portland General Electric Company is the operator of the Boardman power plant. Idaho Power believes that it has sufficient inventory and coal contracts to supply the Boardman plant with fuel through 2016 and has 25 percent of projected fuel needs for 2017. The Boardman plant receives coal through annual contracts with suppliers from the Powder River Basin in northeast Wyoming. Idaho Power expects to meet future coal needs through similar contracts. In December 2010, the Oregon Environmental Quality Commission approved a plan to cease coal-fired operations at the Boardman power plant no later than December 31, 2020.

***Natural Gas-fired Generation*:** Idaho Power owns and operates the Langley Gulch natural gas-fired combined cycle power plant and the Danskin and Bennett Mountain natural gas-fired simple cycle combustion turbine power plants. All three plants are located in Idaho.

Idaho Power operates the Langley Gulch plant as a baseload unit and the Danskin and Bennett Mountain plants to meet peak supply needs. The plants are also used to take advantage of wholesale market opportunities. Natural gas for all facilities is purchased based on system requirements and dispatch efficiency. The natural gas is transported through the Williams-Northwest Pipeline under Idaho Power's 55,584 million British thermal units (MMBtu) per day long-term gas transportation service agreements. These transportation agreements vary in contract length but generally contain the right for Idaho Power to extend the term. In addition to the long-term gas transportation service agreements, Idaho Power has entered into a long-term storage service agreement with Northwest Pipeline for 131,453 MMBtu of total storage capacity at the Jackson Prairie Storage Project. This firm storage contract expires in 2043. Idaho Power purchases and stores natural gas with the intent of fulfilling needs as identified for seasonal peaks or to meet system requirements.

As of December 31, 2015, approximately 9.8 million MMBtu's of natural gas was financially hedged for physical delivery for the operational dispatch of the Langley Gulch plant through January 2017. Idaho Power plans to manage the procurement of additional natural gas for the peaking units on the daily spot market or from storage inventory as necessary to meet system requirements and fueling strategies.

***Purchased Power*:** As described below, Idaho Power purchases power in the wholesale market as well as power pursuant to long-term power purchase contracts and exchange agreements.

Wholesale Market Transactions: To supplement its self-generated power and long-term purchase arrangements, Idaho Power purchases power in the wholesale market based on economics, operating reserve margins, risk management policy limitations, and unit availability. Depending on availability of excess power or generation capacity, pricing, and opportunities in the markets, Idaho Power also sells power in the wholesale markets. During 2015 and 2014, Idaho Power purchased 1.8 million MWh and 1.9 million MWh of power through wholesale market purchases at an average cost of $49.57 per MWh and $49.31 per MWh, respectively. During 2015 and 2014, Idaho Power sold 1.3 million MWh and 2.2 million MWh of power in wholesale market sales, with an average price of $24.63 per MWh and $34.76 per MWh, respectively.

Long-term Power Purchase and Exchange Arrangements: In addition to its wholesale market purchases, Idaho Power has the following notable firm long-term power purchase contracts and energy exchange agreements:

- Telocaset Wind Power Partners, LLC - for 101 MW (nameplate generation) from its Elkhorn Valley wind project located in eastern Oregon. The contract term is through 2027.

- USG Oregon LLC - for 22 MW (estimated average annual output) from the Neal Hot Springs #1 geothermal power plant located near Vale, Oregon. The contract term is through 2037.
- Clatskanie People's Utility - for the exchange of up to 18 MW of energy from the Arrowrock hydroelectric project in southern Idaho in exchange for energy from Idaho Power's system or power purchased at the Mid-Columbia trading hub. The initial term of the agreement was through December 31, 2015, but the term of the agreement has been extended through December 31, 2020. Idaho Power has the right to renew the agreement for one additional five-year term.
- Raft River Energy I, LLC - for up to 13 MW (nameplate generation) from its Raft River Geothermal Power Plant Unit #1 located in southern Idaho. The contract term is through 2033.

PURPA Power Purchase Contracts: Idaho Power purchases power from PURPA projects as mandated by federal law. As of February 5, 2016, Idaho Power had contracts with on-line PURPA-related projects with a total of 784 MW of nameplate generation capacity, with an additional 423 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. The expense and volume of PURPA project power purchases during the last three years is included in the following table:

	Year Ended December 31,		
	2015	**2014**	**2013**
PURPA contract expense (in thousands)	$ 131,340	$ 144,617	$ 131,338
MWh purchased under PURPA contracts (in thousands)	2,008	2,286	2,127
Average cost per MWh from PURPA contracts	$ 65.41	$ 63.26	$ 61.75

Pursuant to the requirements of PURPA, the IPUC and OPUC have each issued orders and rules regulating Idaho Power’s purchase of power from "qualifying facilities" that meet the requirements of PURPA. A key component of the PURPA contracts is the energy price contained within the agreements. PURPA regulations specify that a utility must pay energy prices based on the utility’s avoided costs. The IPUC and OPUC have established specific rules and regulations to calculate the avoided cost that Idaho Power is required to include in PURPA contracts. For PURPA power purchase agreements:

- Idaho Power is required to purchase all of the output from the facilities located inside its service area, subject to some exceptions such as adverse impacts on system reliability.
- Idaho Power is required to purchase the output of projects located outside its service area if it has the ability to receive power at the facility’s requested point of delivery on Idaho Power's system.
- The IPUC jurisdictional portion of the costs associated with PURPA contracts is fully recovered through base rates and the PCA, and the OPUC jurisdictional portion is recovered through general rate case filings and an Oregon PCA mechanism. Thus, the primary impact of high power purchase costs under PURPA contracts is on customer rates.
- The IPUC issued an order in August 2015 that revised the standard PURPA power purchase contract term for new contracts to 2 years from the previously required 20 year term.
- OPUC jurisdictional regulations have generally provided for PURPA standard contract terms of up to 20 years. Various ongoing cases are being processed at the OPUC in which the contract term and other PURPA regulations are being reviewed.
- The IPUC requires Idaho Power to pay "published avoided cost" rates for all wind and solar projects that are smaller than 100 kilowatts (kW) and all other types of projects that are smaller than 10 average MWs. For PURPA qualifying facilities that exceed these size limitations, Idaho Power is required to negotiate an applicable price (premised on avoided costs) based upon IPUC regulations.
- The OPUC requires that Idaho Power pay the published avoided costs for all PURPA qualifying facilities with a nameplate rating of 10 MW or less and that Idaho Power negotiate an applicable price (premised on avoided costs) for all other qualifying facilities based upon OPUC regulations. As part of the ongoing cases at the OPUC, the OPUC has temporarily reduced this nameplate rating for solar and wind projects to 3 MW.

Idaho Power, as well as other affected electric utilities, have engaged in proceedings at the IPUC and OPUC relating to PURPA contracts. Final rulings were issued in the IPUC proceedings in 2015, and the OPUC proceedings are ongoing. These proceedings have related to, among other things, appropriate contract term lengths and the prices paid for energy purchased from PURPA projects. Refer to Part II - Item 7 - MD&A - "Regulatory Matters - *Renewable Energy Contracts and PURPA*" for a summary of those proceedings.

Consideration of Participation in Energy Imbalance Market: Utilities in the western United States outside the California Independent System Operator (California ISO) have traditionally relied upon a combination of automated and manual dispatch within the hour to balance generation and load to maintain reliable supply. These utilities have limited capability to transact within the hour outside their own borders. In contrast, energy imbalance markets use automated intra-hour economic dispatch of generation from committed resources to serve loads. The California ISO and PacifiCorp implemented a new energy imbalance market in 2014 (Western EIM) under which the parties enabled their systems to interact for dispatch purposes. The Western EIM is intended to reduce the power supply costs to serve customers through more efficient dispatch of a larger and more diverse pool of resources, to integrate intermittent power from renewable generation sources more effectively, and to enhance reliability. Participation in the Western EIM is voluntary and available to all balancing authorities in the western United States. Since 2015, Idaho Power has been evaluating the potential power supply cost savings and other advantages, system upgrade requirements, capital and ongoing operating costs, and other aspects of Idaho Power's potential participation in the Western EIM.

Transmission Services

Electric transmission systems deliver energy from electric generation facilities to distribution systems for final delivery to customers. Transmission systems are designed to move electricity over long distances because generation facilities can be located hundreds of miles away from customers. Idaho Power’s generating facilities are interconnected through its integrated transmission system and are operated on a coordinated basis to achieve maximum capability and reliability. Idaho Power’s transmission system is directly interconnected with the transmission systems of the Bonneville Power Administration, Avista Corporation, PacifiCorp, NorthWestern Energy, and NV Energy. These interconnections, coupled with transmission line capacity made available under agreements with some of those entities, permit the interchange, purchase, and sale of power among entities in the Western Interconnection. Idaho Power provides wholesale transmission service for eligible transmission customers on a non-discriminatory basis. Idaho Power is a member of the WECC, the NWPP, the Northern Tier Transmission Group, and the North American Energy Standards Board. These groups have been formed to more efficiently coordinate transmission reliability and planning throughout the Western Interconnection.

Transmission to serve Idaho Power's retail customers is subject to the jurisdiction of the IPUC and OPUC for retail rate making purposes. Idaho Power provides cost-based wholesale and retail access transmission services under the terms of a FERC approved OATT. Services under the OATT are offered on a nondiscriminatory basis such that all potential customers, including Idaho Power, have an equal opportunity to access the transmission system. As required by FERC standards of conduct, Idaho Power's transmission function is operated independently from Idaho Power's energy marketing function.

Idaho Power is jointly working on the permitting of two significant transmission projects. The Boardman-to-Hemingway line is a proposed 300-mile, 500-kV transmission project between a station near Boardman, Oregon and the Hemingway station near Boise, Idaho. The Gateway West line is a proposed 500-kV transmission project between a station located near Douglas, Wyoming and the Hemingway station. Both projects are intended to meet future anticipated resource needs and are discussed in Part II, Item 7 – MD&A - "Liquidity and Capital Resources - Capital Requirements" in this report.

Resource Planning

Integrated Resource Planning: The IPUC and OPUC require that Idaho Power prepare biennially an Integrated Resource Plan (IRP). Idaho Power filed its most recent IRP in June 2015. The IRP seeks to forecast Idaho Power's loads and resources for a 20-year period, analyzes potential supply-side and demand-side resource options, and identifies potential near-term and long-term actions. The four primary goals of the IRP are to:

- identify sufficient resources to reliably serve the growing demand for energy within Idaho Power's service area throughout the 20-year planning period;
- ensure the selected resource portfolio balances cost, risk, and environmental concerns;
- give equal and balanced treatment to both supply-side resources and demand-side measures; and
- involve the public in the planning process in a meaningful way.

During the time between IRP filings, the public and regulatory oversight of the activities identified in the IRP allows for discussion and adjustment of the IRP as warranted. Idaho Power makes periodic adjustments and corrections to the resource plan to reflect economic conditions, anticipated resource development, changes in technology, and regulatory requirements.

The load forecast Idaho Power used for purposes of the 2015 IRP predicts an average annual growth rate of 1.2 percent for average loads and 1.5 percent for summer peak loads over the 20-year planning horizon from 2015 to 2034. The rate of load growth can impact the timing and extent of development of resources, such as new generation plants or transmission infrastructure, to serve those loads. The load forecast Idaho Power used in the 2013 IRP predicted an average annual growth rate of 1.1 percent for average loads and 1.4 percent for summer peak loads over the 20-year planning horizon from 2013 to 2032.

The 2015 IRP identified a preferred resource portfolio, which includes the completion of the Boardman-to-Hemingway 500-kV transmission line and the potential early retirement of the North Valmy power plant, both in 2025, with no other new resource needs prior to 2025. However, as noted in the 2015 IRP, there is considerable uncertainty surrounding the resource sufficiency estimates and project completion dates, including uncertainty around the timing and extent of third party development of renewable resources, implementation of the EPA's rules under Section 111(d) of the Clean Air Act, the actual completion date of the Boardman-to-Hemingway transmission project, and the economics and logistics of plant retirements. These and other uncertainties could result in changes to the desirability of the preferred portfolio and adjustments to the timing and nature of anticipated and actual actions.

The 2015 IRP includes as near-term action items the continued permitting and planning for the Boardman-to-Hemingway transmission line and further investigation of the early retirement of the North Valmy power plant in collaboration with the plant's co-owner. The near-term action plan also includes a decrease in the size of the planned Shoshone Falls expansion from 50 MW to a range of 1.7 MW to 4 MW with a scheduled on-line date in 2019, as well as commencement of an economic evaluation of environmental control retrofits for units 1 and 2 at the Jim Bridger power plant.

Energy Efficiency and Demand Response Programs: Idaho Power's energy efficiency and demand response portfolio is comprised of 22 programs. These energy efficiency and demand response programs target energy savings across the entire year and system demand reduction in the summer. The programs are offered to all customer segments and emphasize the wise use of energy, especially during periods of high demand. This energy and demand reduction can minimize or delay the need for new generation or transmission infrastructure. Idaho Power's programs include:

- financial incentives for irrigation customers for either improving the energy efficiency of an irrigation system or installing new energy efficient systems;
- energy efficiency for new and existing homes including heating, ventilation and cooling equipment, energy efficient building techniques, insulation improvement, air duct sealing, and energy efficient lighting;
- incentives to industrial and commercial customers for acquiring energy efficient equipment, and using energy efficiency techniques for operational and management processes;
- demand response programs to reduce peak summer demand through the voluntary cycling of central air conditioners for residential customers, interruption of irrigation pumps, and reduction of commercial and industrial demand through actions taken by business owners and operators; and
- membership in the Northwest Energy Efficiency Alliance, which supports market transformation efforts across the region.

In 2015, Idaho Power's energy efficiency programs reduced energy usage by approximately 140,000 MWh. For 2015, Idaho Power had a demand response available capacity of approximately 385 MW. In 2015 and 2014, Idaho Power expended approximately $39 million and $37 million, respectively, on both energy efficiency and demand response programs. Funding for these programs is provided through a combination of the Idaho and Oregon energy efficiency tariff riders, base rates, and the Idaho PCA mechanism.

Environmental Regulation and Costs

Idaho Power's activities are subject to a broad range of federal, state, regional, and local laws and regulations designed to protect, restore, and enhance the quality of the environment. Environmental regulation impacts Idaho Power's operations due to the cost of installation and operation of equipment and facilities required for compliance with environmental regulations, the modification of system operations to accommodate environmental regulations, and the cost of acquiring and complying with permits and licenses. In addition to generally applicable regulations, Idaho Power's three coal-fired power plants, three natural gas combustion turbine power plants, and 17 hydroelectric generating plants are subject to a broad range of environmental requirements, including those related to air and water quality, waste materials, and endangered species. For a more detailed discussion of these and other environmental issues, refer to Item 7 - MD&A - "Environmental Matters" in this report.

Environmental Expenditures: Idaho Power's environmental compliance expenditures will remain significant for the foreseeable future, especially given the additional regulations proposed and issued at the federal level. Idaho Power estimates its environmental expenditures, based upon present environmental laws and regulations, will be as follows for the periods indicated, excluding allowance for funds used during construction (AFUDC) (in millions of dollars):

	2016	2017 - 2018
Capital expenditures:		
License compliance and relicensing efforts at hydroelectric facilities	$ 16	$ 27
Investments in equipment and facilities at thermal plants	29	11
Total capital expenditures	$ 45	$ 38
Operating expenses:		
Operating costs for environmental facilities - hydroelectric	$ 22	$ 44
Operating costs for environmental facilities - thermal	14	27
Total operations and maintenance	$ 36	$ 71

Idaho Power anticipates that finalization and implementation of a number of federal and state rulemakings and other proceedings addressing, among other things, greenhouse gases and endangered species, could result in substantially increased operating and compliance costs in addition to the amounts set forth above, but Idaho Power is unable to estimate those costs given the uncertainty associated with potential future regulations. Idaho Power would seek to recover those increased costs through the ratemaking process.

Idaho Power monitors environmental requirements and assesses whether environmental control measures are or remain economically appropriate. Continued review of the economic appropriateness of further investments in coal-fired plants was included in a February 2014 order of the IPUC, in which the IPUC requested that Idaho Power continue monitoring environmental requirements at a national level and account for their impact in resource planning and promptly apprise the IPUC of developments that could impact the company's continued reliance on the North Valmy plant as a coal-fired resource. Idaho Power has been working with the plant's co-owner to monitor environmental requirements and costs associated with the plant, and to develop alignment on potential retirement dates for the plant. In its 2015 IRP, Idaho Power included retirement scenarios ranging from 2019 to 2025 for the North Valmy plant, with a later date within that range being more likely.

Voluntary CO_2 Intensity Reduction Goal: Idaho Power is engaged in voluntary greenhouse gas emissions intensity reduction efforts. In September 2009, IDACORP's and Idaho Power's boards of directors approved guidelines that established a goal to reduce Idaho Power's resource portfolio's average carbon dioxide (CO_2) emissions intensity for the 2010 through 2013 time period to a level of 10 to 15 percent below Idaho Power's 2005 CO_2 emissions intensity of 1,194 lbs CO_2/MWh. The combination of effective utilization of hydroelectric projects, above average stream flows in some years, reduced usage of coal-fired facilities, the purchase of renewable energy, and the addition of the Langley Gulch natural gas-fired power plant positioned Idaho Power to extend its CO_2 emissions intensity reduction goal period for an additional two years, targeting an average reduction of 10 to 15 percent below its 2005 levels for the entire 2010 through 2015 time period. Idaho Power achieved its initial reduction goal, as well as its extended goal through 2015. Idaho Power estimates that its average CO_2 emission intensity from company-owned resources for the 2010 through 2015 period was 21 percent below the 2005 CO_2 emission intensity level.

In 2015, Idaho Power further extended and expanded the goal, seeking to reduce the company-owned resource portfolio average CO_2 emission intensity to 15-20 percent below 2005 levels for the 2010-2017 period.

Carbon Disclosure Project Reporting: Idaho Power's estimated historic CO_2 emissions intensity from its generation facilities, as submitted to the Carbon Disclosure Project, was as follows:

	2010	2011	2012	2013	2014
Emission Intensity (lbs CO_2/MWh)	1,060	677	871	1,129	1,019

IDACORP FINANCIAL SERVICES, INC.

IFS invests in affordable housing developments, which provide a return principally by reducing federal and state income taxes through tax credits and accelerated tax depreciation benefits. IFS has focused on a diversified approach to its investment strategy in order to limit both geographic and operational risk with most of IFS's investments having been made through syndicated funds. IFS is no longer actively pursuing further investment opportunities, but will continue to maintain and manage its current portfolio of investments. At December 31, 2015, the gross amount of IFS's portfolio equaled $182 million in tax credit investments. IFS generated tax credits of $3.3 million, $5.2 million, and $5.5 million in 2015, 2014, and 2013, respectively.

IDA-WEST ENERGY COMPANY

Ida-West operates and has a 50 percent ownership interest in nine hydroelectric projects that have a total generating capacity of 45 MW. Four of the projects are located in Idaho and five are in northern California. All nine projects are "qualifying facilities" under PURPA. Idaho Power purchased all of the power generated by Ida-West's four Idaho hydroelectric projects at a cost of approximately $8 million in 2015 and $9 million in both 2014 and 2013.

EXECUTIVE OFFICERS OF THE REGISTRANTS

The names, ages, and positions of the executive officers of IDACORP and Idaho Power are listed below (in alphabetical order), along with their business experience during at least the past five years. Mr. J. LaMont Keen, a member of IDACORP's and Idaho Power's boards of directors and former President and Chief Executive Officer of IDACORP and Idaho Power, and Mr. Steven R. Keen, are brothers. There are no other family relationships among these officers, nor is there any arrangement or understanding between any officer and any other person pursuant to which the officer was appointed.

DARREL T. ANDERSON, 57

- President and Chief Executive Officer of IDACORP, Inc., May 2014 - present
- President and Chief Executive Officer of Idaho Power Company, January 2014 - present
- President and Chief Financial Officer of Idaho Power Company, January 2012 - December 2013
- Executive Vice President, Administrative Services and Chief Financial Officer of IDACORP, Inc., October 2009 - April 2014
- Executive Vice President, Administrative Services and Chief Financial Officer of Idaho Power Company, October 2009 - December 2011
- Member of the Boards of Directors of both IDACORP, Inc. and Idaho Power Company since September 2013

REX BLACKBURN, 60

- Senior Vice President and General Counsel, IDACORP, Inc. and Idaho Power Company, April 2009 - present

LISA A. GROW, 50

- Senior Vice President of Operations of Idaho Power Company, January 2016 - present
- Senior Vice President - Power Supply of Idaho Power Company, October 2009 - December 2015

STEVEN R. KEEN, 55

- Senior Vice President - Chief Financial Officer, and Treasurer of IDACORP, Inc., May 2014 - present
- Senior Vice President - Chief Financial Officer, and Treasurer of Idaho Power Company, January 2014 - present
- Vice President - Finance and Treasurer of IDACORP, Inc., June 2010 - April 2014
- Senior Vice President - Finance and Treasurer of Idaho Power Company, January 2012 - December 2013
- Vice President - Finance and Treasurer of Idaho Power Company, June 2010 - December 2011
- Vice President and Treasurer of IDACORP, Inc. and Idaho Power Company, June 2006 - May 2010

LONNIE KRAWL, 52

- Senior Vice President of Administrative Services and Chief Information Officer of Idaho Power Company, January 2016 - present
- Vice President and Chief Information Officer of Idaho Power Company, October 2013 - December 2015
- Director of Human Resources of Idaho Power Company, July 2009 - September 2013

DANIEL B. MINOR, 58

- Executive Vice President of Idaho Power Company, January 2016 - present
- Executive Vice President and Chief Operating Officer of Idaho Power Company, January 2012 - December 2015
- Executive Vice President of IDACORP, Inc., May 2010 - present
- Executive Vice President - Operations of Idaho Power Company, October 2009 - December 2011

TESSIA PARK, 54

- Vice President of Power Supply of Idaho Power Company, January 2016 - present
- Director of Load Serving Operations of Idaho Power Company, September 2012 - December 2015
- Operating Projects Manager of Idaho Power Company, January 2011 - September 2012
- Manager of Power Supply Operations of Idaho Power Company, August 2009 - January 2011

KEN W. PETERSEN, 52

- Vice President, Controller and Chief Accounting Officer of IDACORP, Inc. and Idaho Power Company, January 2014 - present
- Corporate Controller and Chief Accounting Officer of IDACORP, Inc. and Idaho Power Company, May 2010 - December 2013
- Corporate Controller of IDACORP, Inc. and Idaho Power Company, December 2007 - May 2010

N. VERN PORTER, 56

- Vice President of Customer Operations of Idaho Power Company, January 2016 - present
- Senior Vice President of Customer Operations of Idaho Power Company, April 2015 - December 2015
- Vice President of Idaho Power Company, January 2014 - April 2015
- Vice President of Delivery Engineering and Construction of Idaho Power Company, May 2012 - December 2013
- Vice President of Delivery Engineering and Operations of Idaho Power Company, October 2009 - May 2012

ITEM 1A. RISK FACTORS

IDACORP and Idaho Power operate in a highly regulated industry and business environment that involves significant risks, many of which are beyond the companies' control. The circumstances and factors set forth below may have a material impact on the business, financial condition, or results of operations of IDACORP and Idaho Power and could cause actual results or outcomes to differ materially from those discussed in any forward-looking statements. These risk factors, as well as other information in this report and in other reports the companies file with the SEC, should be considered carefully when making any investment decisions relating to IDACORP or Idaho Power.

If state public utility commissions or the Federal Energy Regulatory Commission authorize customer rates that under-collect or untimely collect through rates the amount Idaho Power needs to cover costs and earn a reasonable rate of return, IDACORP's and Idaho Power's financial condition and results of operations may be adversely affected. The prices that the Idaho Public Utilities Commission (IPUC) and Public Utility Commission of Oregon (OPUC) authorize Idaho Power to charge customers for its retail services, and the tariff rate that the Federal Energy Regulatory Commission (FERC) permits Idaho Power to charge for its transmission services, are generally the most significant factors influencing IDACORP’s and Idaho Power’s business, results of operations, and financial condition. Idaho Power's ability to recover its costs and earn a reasonable rate of return can be affected by many factors, including the time lag between when costs are incurred and when those costs are recovered in customers’ rates, and differences between the costs embedded in rates and the amount of actual costs incurred. Idaho Power is often required to incur costs before the IPUC, OPUC, or FERC approves the recovery of those costs, and the IPUC, OPUC, and FERC may not allow Idaho Power to recover costs on the basis that such costs were not reasonably or prudently incurred or for other reasons. While rate regulation is premised on the assumption that rates will be established that are fair, just, and reasonable, regulators have considerable discretion in applying this standard. The ratemaking process typically involves multiple intervening parties, including governmental bodies, consumer advocacy groups, and customers, generally with the common objective of limiting rate increases or even reducing rates. Denial or probable denial of recovery by regulators may cause Idaho Power to record an impairment of its assets. In a number of proceedings in recent years, Idaho Power has been denied recovery, or required to defer recovery pending the next general rate case, including denials or deferrals related to compensation expenses.

For additional information relating to Idaho Power's regulatory framework and regulatory matters, see Part I - Item 1 - "Business - Utility Operations," Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report, and Part II - Item 7 - "Management's Discussion and Analysis of Financial Condition and Results of Operations - Regulatory Matters" in this report.

Idaho Power's cost recovery mechanisms may not function as intended and are subject to change, which may adversely affect IDACORP's and Idaho Power's financial condition and results of operations. Idaho Power has power cost adjustment mechanisms in its Idaho and Oregon jurisdictions and a fixed cost adjustment mechanism in Idaho that provide for periodic adjustments to the rates charged to its retail customers. The power cost adjustment mechanisms track Idaho Power’s actual net power supply costs (primarily fuel and purchased power less off-system sales) and compare these amounts to net power supply costs being recovered in retail rates. A majority of the difference between these two amounts is deferred for future recovery from, or refund to, customers through rates. In recent years, the volatility in power supply costs has been significant, in large part due to changes in hydroelectric generation conditions and the cost of purchase of renewable energy under long-term contracts. While the power cost adjustment mechanisms function to mitigate the potentially adverse impact on net income of power supply cost volatility, the mechanisms do not eliminate the cash flow impact of that volatility. When power costs rise above the level recovered in current retail rates, Idaho Power incurs the costs but recovery of those costs is deferred to a subsequent collection period, which can adversely affect Idaho Power's operating cash flow and liquidity until those costs are recovered from customers. The fixed cost adjustment mechanism is a decoupling mechanism designed to remove Idaho Power's disincentive to invest in energy efficiency activities by allowing Idaho Power to charge residential and small commercial customers when it recovers less than the base level of fixed costs per customer that the IPUC authorized for recovery in the most recent general rate case. Both the power cost and fixed cost adjustment mechanisms were approved through the regulatory process, and thus they are subject to change at the discretion of applicable state regulators, who could decide to modify or eliminate either mechanism in a manner that adversely impacts IDACORP's and Idaho Power's financial condition, cash flows, and results of operations.

IDACORP's and Idaho Power's business, financial condition, and results of operations may be negatively affected by changes in customer growth or customer usage. Growth in the number of customers and customers' usage of electricity are affected by a number of factors, such as population growth or decline in Idaho Power's service area, adoption rates of energy efficiency measures, customer-generated power such as from rooftop solar panels, demand side management requirements, and economic conditions. Many electric utilities have experienced a decline in usage per customer, in part attributable to energy efficiency activities. While Idaho Power has recently experienced a net growth in usage due to an increase in the number of customers, when adjusted for the impacts of weather the average monthly usage on a per customer basis for Idaho residential customers has declined from 1,059 kWh in 2009 to 1,012 kWh in 2014. Rate mechanisms, such as the Idaho fixed cost adjustment, are designed to address the financial disincentive associated with promoting energy efficiency activities, but there is no assurance that the mechanism will result in full or timely collection of Idaho Power's fixed costs, which are currently collected in large part through the company's kWh energy rates that are based on historical sales volume. Any undercollection of fixed costs would adversely impact revenues, earnings, and cash flows. Weak economic conditions may also reduce the amount of energy Idaho Power's customers consume, result in a loss of customers (including large-load industrial and commercial customers) or further decrease the customer growth rate, and increase the likelihood and prevalence of late payments and uncollectible accounts. The formation of municipal utilities or similar entities for distribution systems within Idaho Power's service area could also result in a load decrease. The loss of loads resulting from some of these events may result in IDACORP and Idaho Power modifying or eliminating large generation or transmission projects. This could in turn result in write-downs or write-offs if regulators determine that the costs of the projects were incurred imprudently, which could have a material adverse impact on IDACORP's and Idaho Power's financial condition, results of operations, and cash flows.

Conversely, if Idaho Power were to experience an unanticipated increase in the demand for energy through, for example, the rapid addition of new industrial and commercial customers, Idaho Power may be required to rely on higher-cost purchased power to meet peak system demand and may need to accelerate investment in additional generation or transmission resources. If the incremental costs associated with the unanticipated changes in loads exceed the incremental revenue received from the sales to the new customers, and Idaho Power is unable to secure timely and full rate relief to recover those increased costs, the resulting imbalance could have an adverse effect on IDACORP's and Idaho Power's financial condition, results of operations, and cash flows.

IDACORP's and Idaho Power's operating results fluctuate seasonally and can be adversely affected by changes in weather conditions and severe weather. Idaho Power's electric power sales are seasonal, with demand in Idaho Power's service area peaking during the hot summer months, with a secondary peak during the cold winter months. Electric power demands by irrigation customers in Idaho Power's service area, which are impacted by temperatures and the timing and amount of precipitation, among other factors, can also create significant seasonal changes in usage. Seasonality of revenues may be further impacted by Idaho Power's tiered rate structure, under which rates charged to customers are often higher during higher-load periods. Market prices for power also often increase significantly during these peak periods, at times when Idaho Power is required to purchase power in the wholesale markets to meet customer demand. By contrast, when temperatures are relatively mild or where precipitation supplants irrigation systems, loads are often lower as customers are not using electricity for heating and air conditioning or irrigation purposes. Thus, weather conditions and the timing and extent of precipitation can cause IDACORP's and Idaho Power's results of operations and financial condition to fluctuate seasonally, quarterly, and from year to year.

Extreme weather events and their associated impacts (such as fires, high winds, and snow loading) can damage generation facilities and disrupt transmission and distribution systems, causing service interruptions and extended outages through downed transmission and distribution lines, increasing supply chain costs and limiting Idaho Power's ability to meet customer energy demand. Sustained drought conditions are likely to decrease power generation from hydroelectric plants. The effect of the failure of Idaho Power's facilities to operate as planned under extreme weather conditions is particularly burdensome during peak demand periods, such as hot summer days. Damage and disruption in generation, transmission, and distribution systems due to weather-related factors also increases operations and maintenance expenses. Costs incurred as a result of such events might not be recovered through customer rates if the costs incurred are greater than those allowed for recovery by regulators, and the costs of repair and replacing infrastructure or liability for personal injury or property damage may not be covered in full by insurance.

New advances in power generation, energy efficiency, or other technologies that impact the power utility industry could decrease revenues. The increasing cost of energy in the electric utility industry has encouraged the development of new technologies for power generation, power storage, and energy efficiency. In particular, in recent years the cost of solar generation has decreased significantly, and there are federal tax incentives in place to help further reduce the cost of solar generation. There is potential that customer-owned power generation systems, particularly if coupled with power storage devices, could become sufficiently cost-effective and efficient that an increasing number of Idaho Power's customers choose to install such systems on their homes or businesses. Additionally, considerable emphasis has been placed on energy efficiency, such as LED lighting and high-efficiency appliances. Energy efficiency programs, including programs sponsored by Idaho Power under a directive from state regulatory commissions, are designed to reduce energy demand. If Idaho Power is unable to adjust its rate design or maintain adequate regulatory mechanisms allowing for timely cost recovery, declining usage from customer-owned generation sources and energy efficiency would result in under-recovery of Idaho Power's costs and reduce revenues, which would impact IDACORP's and Idaho Power's financial condition and results of operations.

Capital expenditures for infrastructure, risks associated with construction of that infrastructure, and the timing and availability of cost recovery for the expenditures, can significantly affect IDACORP's and Idaho Power's financial condition and results of operations. Idaho Power’s business is capital intensive and requires significant investments in energy generation, transmission, and distribution infrastructure. A significant portion of Idaho Power’s facilities were constructed many years ago, and thus require periodic upgrades and frequent maintenance. Also, long-term anticipated increases in both the number of customers and the demand for energy require expansion and reinforcement of that infrastructure. For instance, Idaho Power is in the permitting process for two 500-kV transmission line projects, which are intended to help meet future customer energy demands. Construction projects are subject to usual permitting and construction risks that can adversely affect project costs and the completion time. These risks include, as examples:

- the ability to timely obtain labor or materials at reasonable costs, and defaults by contractors;
- equipment, engineering, and design failures;
- the effects of adverse weather conditions;
- availability of financing;
- the ability to obtain and comply with permits and land use rights, and environmental constraints;
- delays and costs associated with disputes and litigation with third parties; and
- changes in applicable laws or regulations.

If Idaho Power is unable to complete the construction of a project, or incurs costs that regulators do not deem prudent, it may be unable to recover its costs in full through rates or on a timely basis. Further, if Idaho Power is unable to secure permits or joint funding commitments to develop transmission infrastructure necessary to serve loads, it may terminate those projects and, as an alternative, seek to develop additional generation facilities within areas where Idaho Power has available transmission capacity or pursue other more costly options to serve loads. To limit the timing-related risks of these projects, Idaho Power may enter into purchase orders and construction contracts and incur engineering and design service costs in advance of receiving necessary regulatory approvals or permits. If any of the projects are canceled for any reason, including Idaho Power's failure to receive necessary regulatory approvals or permits or because the project is no longer economical, Idaho Power could incur significant cancellation penalties under purchase orders or construction contracts. Additionally, termination of a project carries with it the potential for impairment of the associated asset if regulators deny full recovery of project costs. Thus, termination of a project could negatively affect IDACORP's and Idaho Power's financial condition and results of operations.

IDACORP's and Idaho Power’s businesses are subject to an extensive set of environmental laws, rules, and regulations, which could impact their operations and increase costs of operations, potentially rendering some generating units uneconomical to maintain or operate, and could increase the costs and alter the timing of major projects. A number of federal, state, and local environmental statutes, rules, and regulations relating to air and water quality, natural resources, renewable energy certificates, and health and safety are applicable to IDACORP's and Idaho Power's operations. Many of these laws and regulations are described in Part II - Item 7 - "Management's Discussion and Analysis of Financial Condition and Results of Operations - Environmental Matters" in this report. These laws and regulations generally require IDACORP and Idaho Power to obtain and comply with a wide variety of environmental licenses, permits, and other approvals, including through substantial investment in pollution controls, and may be enforced by both public officials and private individuals. Some of these regulations are pending, changing, or subject to interpretation, and failure to comply may result in penalties, mandatory operational changes, and other adverse consequences, including costs associated with defending against claims by governmental authorities or private parties and complying with new operating requirements. Idaho Power devotes significant resources to environmental monitoring, pollution control equipment, and mitigation projects to comply with existing and anticipated environmental regulatory requirements. However, the current trend is toward more stringent standards, stricter regulation, and more expansive application of environmental regulations.

Environmental regulations have created the need for Idaho Power to install new pollution control equipment at, and may cause Idaho Power to perform environmental remediation on, its owned and co-owned power generation facilities, often at a substantial cost. For instance, Idaho Power is installing environmental control apparatus in two units of its co-owned Jim Bridger power plant at an estimated cost of $105 million, and may install a second set of control apparatus at two other units at that plant in or around 2021 and 2022. IDACORP and Idaho Power will incur other costs associated with existing environmental regulations, and the companies expect to incur additional costs associated with pending and future environmental regulations, and those costs are likely to be substantial. In some cases, the costs to obtain permits and ensure facilities are in compliance may be prohibitively expensive. If the costs of compliance with those new regulations renders the generating facilities uneconomical to maintain or operate, Idaho Power would need to identify alternative resources for power, potentially in the form of new generation and transmission facilities, market power purchases, demand-side management programs, or a combination of these and other methods. Furthermore, Idaho Power may not be able to obtain or maintain all environmental regulatory approvals necessary for operation of its existing infrastructure or construction of new infrastructure.

Idaho Power is not guaranteed timely or full recovery through customer rates of costs associated with environmental regulations, environmental compliance, and clean-up of contamination, and regulators may not grant prior approval of cost recovery. For example, in 2013 the IPUC declined to approve Idaho Power's application requesting a binding commitment to provide rate base treatment for Idaho Power's estimated share of the capital investment in environmental control upgrades at the Jim Bridger power plant, instead reserving the prudence determination (and thus ratemaking treatment) for subsequent proceedings. If there is a delay in obtaining any required environmental regulatory approval or if Idaho Power fails to obtain, maintain, or comply with any such approval, construction and/or operation of Idaho Power's generation or transmission facilities could be delayed, halted, or subjected to additional costs.

Factors contributing to lower hydroelectric generation can increase costs and negatively impact IDACORP's and Idaho Power's financial condition and results of operations. Idaho Power derives a significant portion of its power supply from its hydroelectric facilities. During 2015, 47 percent of Idaho Power's electric power generation was from hydroelectric facilities. Because of Idaho Power’s heavy reliance on hydroelectric generation, factors such as precipitation and snow pack, the timing of run-off, and the availability of water in the Snake River basin can significantly affect its operations. The combination of a long-term trend of declining Snake River base flows, over-appropriation of water, and periods of drought have led to water rights disputes and proceedings among surface water and ground water irrigators and the State of Idaho. Recharging the Eastern Snake Plain aquifer by diverting surface water to porous locations and permitting it to sink into the aquifer is one approach to the over-appropriation dispute. Diversions from the Snake River for aquifer recharge or the loss of water rights reduce Snake River flows available for hydroelectric generation. When hydroelectric generation is reduced, Idaho Power must increase its use of more expensive thermal generating resources and market power purchases; therefore, costs increase and opportunities for off-system sales are reduced, reducing revenues and potentially earnings. Through its power cost adjustment mechanisms, Idaho Power expects to recover most (but not all) of the increase in net power supply costs caused by lower hydroelectric generation. The timing of recovery of the increased costs, however, may not occur until the subsequent power cost adjustment year, adversely affecting cash flows and liquidity.

Obligations imposed in connection with hydroelectric license renewals may require large capital expenditures, increase operating costs, reduce hydroelectric generation, and negatively affect IDACORP's or Idaho Power's results of operations and financial condition. For the last several years, Idaho Power has been engaged in an effort to renew its federal license for its largest hydroelectric generation source, the Hells Canyon Complex. Relicensing includes an extensive public review process that involves numerous natural resource issues and environmental conditions. The existence of endangered and threatened species in the watershed may result in major operational changes to the region’s hydroelectric projects, which may be reflected in hydroelectric licenses, including for the Hells Canyon Complex. In addition, new interpretations of existing laws and regulations could be adopted or become applicable to hydroelectric facilities, which could further increase required expenditures for marine life recovery and endangered species protection and reduce the amount of hydroelectric generation available to meet Idaho Power's generation requirements. One particularly significant issue identified in connection with the Hells Canyon Complex relicensing effort involves water temperature gradients in the Snake River below the Hells Canyon dam. Certain parties in the relicensing proceedings have advocated for the installation of a water temperature management apparatus which, if required to be installed, would involve substantial costs to construct, operate, and maintain. Idaho Power may be unable to recover in full or in a timely manner the costs of such an apparatus through rates, particularly given the magnitude of any potential impact on customer rates. Idaho Power also cannot predict the requirements that might be imposed during the relicensing process, the financial impact of those requirements, whether a new multi-year license will ultimately be issued, and whether the IPUC or OPUC will allow recovery through rates of the substantial costs incurred in connection with the licensing process and subsequent compliance. Imposition of onerous conditions in the relicensing process could result in Idaho Power incurring significant capital expenditures, increase operating costs (including power purchase costs), and reduce hydroelectric generation, which could negatively affect results of operations and financial condition.

Idaho Power's use of coal and natural gas to fuel power generation facilities exposes it to commodity availability and price risk, which can adversely affect IDACORP's and Idaho Power's results of operations and financial condition. As part of its normal business operations, Idaho Power purchases coal and natural gas in the open market or under short-term or long-term contracts, often with variable pricing terms. Market prices for coal and natural gas are influenced by factors impacting supply and demand such as weather conditions, fuel transportation availability, economic conditions, and changes in technology. Natural gas transportation to Idaho Power's three natural gas plants is limited to one primary pipeline, presenting a heightened possibility of supply constraint and disruptions separate from the risk of counterparty default. Most of Idaho Power's coal supply arrangements are under long-term contracts for coal originating in Wyoming, and thus Idaho Power is exposed to risk of disruption of coal production in, or transportation from, that region. Idaho Power may from time to time enter into new, or renegotiate, these long-term contracts but can provide no assurance that such contracts will be negotiated or renegotiated on satisfactory terms, or at all. There also can be no assurance that counterparties to the natural gas or coal supply agreements will fulfill their obligations to supply natural gas or coal, and they may experience financial or technical problems that inhibit their ability to deliver natural gas or coal. Defaults by coal and natural gas suppliers may cause Idaho Power to seek alternative, and potentially more costly, sources of fuel or rely on other generation sources or wholesale market power purchases. Idaho Power may not be able to fully or timely recover these increased costs through rates, which may adversely affect IDACORP's and Idaho Power's financial condition and results of operations.

Idaho Power's generation, transmission, and distribution facilities are subject to numerous operational risks unique to it and its industry. Operating risks associated with Idaho Power's generation, transmission, and distribution facilities include equipment failures, volatility in fuel and transportation pricing, interruptions in fuel supplies, increased regulatory compliance costs, labor disputes, accidents and workforce safety matters, release of hazardous or toxic substances into the air, water, or ground, acts of terrorism or sabotage, the loss of cost-effective disposal options for solid waste such as coal ash, operator error, and the occurrence of catastrophic events at the facilities. Diminished availability or performance of those facilities could result in reduced customer satisfaction, reputational harm, and regulatory inquiries and fines. Operation of Idaho Power's owned and co-owned generating stations below expected capacity levels, or unplanned outages at these stations, could cause reduced energy output and lower efficiency levels and result in lost revenues and increased expenses for alternative fuels or wholesale market power purchases. Accidents, electrical contacts, fires, explosions, catastrophic failures, general system damage or dysfunction, and other unplanned events related to Idaho Power's infrastructure would increase repair costs and may expose Idaho Power to claims for personal injury and property damage. Further, the transmission system in Idaho Power's service territory is constrained, limiting the ability to transmit electric energy within the service territory and access electric energy from outside the service territory during high-load periods. Idaho Power's transmission facilities are also interconnected with those of third parties, and thus operation of Idaho Power's and third parties' facilities could be adversely affected by unexpected or uncontrollable events. These transmission constraints and events could result in failure to provide reliable service to customers and the inability to deliver energy from generating facilities to the power grid, or not being able to access lower cost sources of electric energy, which could have a negative effect on IDACORP's and Idaho Power's financial condition and results of operations.

Volatility in the financial markets, failure of IDACORP or Idaho Power to satisfy conditions necessary for obtaining loans or issuing debt securities, and denial of regulatory authority to issue debt or equity securities may negatively affect IDACORP's and Idaho Power's ability to access capital and/or increase their cost of borrowing. IDACORP and Idaho Power use credit facilities, commercial paper markets, and long-term debt as significant sources of liquidity and funding for operating and capital requirements and debt maturities not satisfied by operating cash flow. The credit facilities represent commitments by the participating banks to make loans and issue letters of credit. However, the obligation of the participating banks to make those loans and issue letters of credit is subject to specified conditions. Idaho Power's ability to issue long-term debt is also subject to a number of conditions included in an indenture, and Idaho Power's ability to issue long-term debt and commercial paper is subject to the availability of purchasers willing to purchase the securities under reasonable terms or at all. Because of these limitations, IDACORP and Idaho Power may be unable to issue commercial paper or short-term or long-term debt at reasonable interest rates and terms or at all. Also, while the credit facilities represent a contractual obligation to make loans, one or more of the participating banks may default on their obligations to make loans under, or may withdraw from, the credit facilities.

Idaho Power is required to obtain regulatory approval in Idaho, Oregon, and Wyoming in order to borrow money or to issue securities and is therefore dependent on the public utility commissions of those states to issue favorable orders in a timely manner to permit them to finance their operations, capital expenditures, and debt maturities. Without additional state regulatory approval, as of the date of this report the aggregate amount of short-term borrowings by Idaho Power at any one time outstanding may not exceed $450 million. Also, IDACORP's and Idaho Power's credit facilities include financial covenants that limit the amount of debt that can be outstanding as a percentage of total capital, and Idaho Power's long-term debt has also been issued under an indenture that contains a number of financial covenants. Failure to maintain these covenants could preclude IDACORP and Idaho Power from issuing commercial paper, borrowing under their credit facilities, or issuing long-term debt, and could trigger a default and repayment obligation under debt instruments, which could adversely impact IDACORP's and Idaho Power's financial condition, results of operations, and liquidity.

A downgrade in IDACORP’s and Idaho Power’s credit ratings could affect the companies’ ability to access capital, increase their cost of borrowing, and require the companies to post collateral with transaction counterparties. Credit rating agencies periodically review the corporate credit ratings and long-term ratings of IDACORP and Idaho Power. These ratings are premised on financial ratios and performance, the regulatory environment and rate mechanisms, the effectiveness of management, resource risks and power supply costs, and other factors. IDACORP and Idaho Power also have borrowing arrangements that rely on the ability of the banks to fund loans or support commercial paper, a principal source of short-term financing. Downgrades of IDACORP’s or Idaho Power’s credit ratings, or those affecting relationship banks, could limit the companies’ ability to access short- and long-term capital under reasonable terms or at all, require the companies to pay a higher interest rate on their debt, and require the companies to post additional performance assurance collateral with transaction counterparties.

Idaho Power’s risk management policy and programs relating to economically hedging commodity exposures and credit risk may not always perform as intended, and as a result IDACORP and Idaho Power may suffer economic losses. Idaho Power enters into transactions to hedge its positions in coal, natural gas, power, and other commodities, and enters into financial hedge transactions to mitigate in part exposure to variable commodity prices. IDACORP and Idaho Power could recognize financial losses as a result of volatility in the market value of these contracts or if a counterparty fails to perform. The derivative instruments used for hedging might not offset the underlying exposure being mitigated as intended, due to pricing inefficiencies or other terms of the derivative instruments, and any such failure to mitigate exposure could result in financial losses. Certain of Idaho Power's hedging and derivative agreements may result in the receipt of, or posting of, collateral with counterparties. Fluctuations in commodity prices that lead to the posting of collateral with counterparties negatively impact liquidity, and downgrades in Idaho Power's credit ratings may lead to additional collateral posting requirements. Further, forecasts of future fuel needs and loads and available resources to meet those loads are inherently uncertain and may cause Idaho Power to over- or under-hedge actual resource needs, exposing the company to market risk on the over- or under-hedged position. To the extent that commodity markets are illiquid, Idaho Power may not be able to execute its risk management strategies, which could result in undesired over-exposure to unhedged positions. As a result, risk management actions, or the failure or inability to manage commodity price and counterparty risk, may adversely affect IDACORP’s and Idaho Power’s financial condition and results of operations.

Idaho Power could be subject to penalties and operational changes if it violates mandatory reliability and security requirements, which could adversely impact IDACORP's and Idaho Power's results of operations and financial condition. As an owner and operator of a bulk power transmission system, Idaho Power is subject to mandatory reliability standards issued by the North American Electric Reliability Corporation and enforced by the FERC. The standards are based on the functions that need to be performed to ensure the bulk power system operates reliably and are guided by reliability and market interface principles. Compliance with reliability standards subjects Idaho Power to higher operating costs and increased capital expenditures. Idaho Power has received in recent years notices of violations from, and regularly self-reports reliability standard compliance issues to, the FERC, the North American Electric Reliability Corporation, and the Western Electricity Coordinating Council. Potential monetary and non-monetary penalties for a violation of FERC regulations may be substantial, and in some circumstances monetary penalties may be as high as $1 million per day per violation. The imposition of penalties on Idaho Power for its actual or alleged failure to comply with reliability and security requirements could have a negative effect on its and IDACORP’s results of operations and financial condition.

Federally mandated purchases of power from renewable energy projects, and integration of power generated from those projects into Idaho Power's system, may increase costs and decrease system reliability, and adversely affect Idaho Power's and IDACORP's results of operations and financial condition. An abundance of intermittent, non-dispatchable generation from renewable energy projects interconnected with Idaho Power's system has had an impact on the operation of Idaho Power's generation plants, system reliability, power supply costs, and the wholesale power markets in the Pacific Northwest. Idaho Power is generally obligated under federal law to purchase power from certain renewable energy projects, regardless of the then-current load demand, availability of lower cost generation resources, or wholesale energy market prices. This increases the likelihood and frequency that Idaho Power will be required to reduce output from its lower-cost hydroelectric and fossil fuel-fired generation resources, which in turn increases power purchase costs and customer rates. Further, balancing load and generation from Idaho Power's power generation portfolio is challenging, and Idaho Power expects that its operational costs will continue to increase as a result of its efforts to integrate intermittent, non-dispatchable generation from a large number of renewable energy projects. If Idaho Power is unable to timely recover those costs through its power cost adjustment mechanisms or otherwise, those increased costs may negatively affect IDACORP's and Idaho Power's results of operations, financial condition, and cash flows.

The performance of pension and postretirement benefit plan investments and other factors impacting plan costs and funding obligations could adversely affect IDACORP's and Idaho Power's financial condition and results of operations - primarily cash flows and liquidity. Idaho Power provides a noncontributory defined benefit pension plan covering most employees, as well as a defined benefit postretirement benefit plan (consisting of health care and death benefits) that covers eligible retirees. Costs of providing these benefits are based in part on the value of the plans' assets and, therefore, adverse investment performance for these assets could increase Idaho Power’s plan costs and funding requirements related to the plans. The key actuarial assumptions that affect funding obligations are the expected long-term return on plan assets and the discount rate used in determining future benefit obligations. Idaho Power evaluates the actuarial assumptions on an annual basis, taking into account changes in market conditions, trends, and future expectations. Estimates of future equity and debt market performance, changes in interest rates, and other factors Idaho Power and its actuary firms use to develop the actuarial assumptions are inherently uncertain, and actual results could vary significantly from the estimates. Changes in demographics, including timing of retirements or changes in life expectancy assumptions, may also increase Idaho Power's plan costs and funding requirements. Future pension funding requirements and the timing of funding payments are also subject to the impacts of changes in legislation. Depending on the timing of contributions to the plans and Idaho Power's ability to recover costs through rates, cash contributions to the plans could reduce the cash available for the companies' businesses and payment of dividends. For additional information regarding Idaho Power's funding obligations under its benefit plans, see Note 11 - "Benefit Plans" to the consolidated financial statements included in this report.

As a holding company, IDACORP does not have its own operating income and must rely on the cash flows from its subsidiaries to pay dividends and make debt payments. IDACORP is a holding company with no significant operations of its own, and its primary assets are shares or other ownership interests of its subsidiaries, primarily Idaho Power. IDACORP’s subsidiaries are separate and distinct legal entities and have no obligation to pay any amounts to IDACORP, whether through dividends, loans, or other means. The ability of IDACORP’s subsidiaries to pay dividends or make distributions to IDACORP depends on several factors, including each subsidiary's actual and projected earnings and cash flow, capital requirements and general financial condition, regulatory restrictions, covenants contained in credit facilities to which they are parties, and the prior rights of holders of their existing and future first mortgage bonds and other debt or equity securities. Further, the amount and payment of dividends is at the discretion of the board of directors, which may reduce or cease payment of dividends at any time. See Note 6 - "Common Stock" to the consolidated financial statements included in this report for a further description of restrictions on IDACORP's and Idaho Power's payment of dividends.

IDACORP's and Idaho Power's activities are concentrated in one industry and in one region, which exposes it to risks from lack of diversification, regional economic conditions, and regional legislation and regulation. IDACORP and Idaho Power do not have diversified operations or sources of revenue. Idaho Power comprises the bulk of IDACORP's operations, and Idaho Power's business is concentrated solely in the electricity industry. Furthermore, Idaho Power's provision of electric service to retail customers is conducted exclusively in its southern Idaho and eastern Oregon service area. As a result, IDACORP's and Idaho Power's future performance will be affected by economic conditions, regulatory and legislative activity, and other events in its service area and in the electric power industry.

The impacts of a retiring workforce with specialized utility-specific functions could increase costs and adversely affect IDACORP's and Idaho Power's financial condition and results of operations. Idaho Power's operations require a skilled workforce to perform specialized utility functions. Many of these positions, such as linemen, grid operators, and generation plant operators, require extensive, specialized training. Idaho Power has experienced in recent years an above-average number of employee retirements and expects the increased level of retirement of its skilled workforce and persons in key positions will continue in 2016 and in the near-term. This will require Idaho Power to attract, train, and retain new employees to help prevent a loss of institutional knowledge and avoid a skills gap. The loss of skills and institutional knowledge of experienced employees and the costs associated with attracting, training, and retaining appropriately qualified employees to replace an aging and skilled workforce could have a negative effect on IDACORP's and Idaho Power's financial condition and results of operations.

IDACORP and Idaho Power are subject to costs and other effects of legal and regulatory proceedings, disputes, and claims. From time to time in the normal course of business IDACORP and Idaho Power are subject to various lawsuits, regulatory proceedings, disputes, and claims that could result in adverse judgments or settlements, fines, penalties, injunctions, or other adverse consequences. These matters are subject to a number of uncertainties, and as a result management is often unable to predict the outcome of a matter. Two notable existing legal proceedings are described in Note 10 - "Contingencies" to the consolidated financial statements included in this report. The legal costs and final resolution of matters in which IDACORP or Idaho Power are involved could have a negative effect on their financial condition and results of operations. Similarly, the terms of resolution could require the companies to change their operational practices and procedures, which could also have a negative effect on their financial positions and results of operations.

Acts or threats of terrorism, cyber attacks, data or physical security breaches, and other acts of individuals or groups seeking to disrupt Idaho Power's operations or the electric power grid could negatively impact IDACORP's and Idaho Power's financial condition and results of operations. Idaho Power operates in an industry that requires the continuous use and operation of sophisticated information technology systems and network infrastructure. Idaho Power's generation and transmission facilities and its grid operations are potential targets for terrorist acts and threats, as well as cyber attacks and other disruptive activities of individuals or groups. Some of Idaho Power's facilities are deemed "critical infrastructure," in that incapacity or destruction of the facilities could have a debilitating impact on security, reliability or operability of the bulk electric power system, national economic security, and public health and safety. The possibility that infrastructure facilities, such as generation facilities and electric transmission facilities, would be direct targets of, or indirect casualties of, an act of terror or cyber attack (whether originating internally or externally) may affect Idaho Power's operations by limiting the ability to generate, purchase, or transmit power. These events, and governmental actions in response, could result in a material decrease in revenues and increase costs to protect, repair, and insure Idaho Power's assets and operate its business.

Federal regulators have stated that a number of organizations continue to seek opportunities to exploit potential vulnerabilities in the U.S. energy infrastructure and that those attacks have become increasingly sophisticated. Attacks on Idaho Power's infrastructure could result from acts of those organizations or other third parties as well as Idaho Power employees or contractors. At the same time, Idaho Power's energy infrastructure is becoming more reliant on network-based infrastructure. Idaho Power's operations require the continuous availability of information technology systems and network infrastructure, and in the normal course of business Idaho Power collects sensitive and confidential customer and employee information and proprietary information of Idaho Power. Although Idaho Power actively monitors developments in cyber security, no security measures can completely shield Idaho Power's systems, infrastructure, and data from vulnerabilities to cyber attacks, intrusions, or other catastrophic events that could result in their failure or reduced functionality, and ultimately the potential loss of sensitive information or the loss of Idaho Power's ability to fulfill critical business functions and provide reliable electric power to customers. The loss of data could result in violations of privacy and other laws, financial loss to Idaho Power or to its customers, customer dissatisfaction, and significant litigation exposure, all of which could materially affect Idaho Power's financial condition and results of operations.

Changes in tax laws and regulations, or differing interpretation or enforcement of applicable laws by the Internal Revenue Service or other taxing jurisdictions, could have a material adverse impact on IDACORP's or Idaho Power's financial condition and results of operations. IDACORP and Idaho Power must make judgments and interpretations about the application of the law when determining the provision for taxes. Amounts of tax-related assets and liabilities involve judgments and estimates of the timing and probability of recognition of income, deductions, and tax credits, which are subject to challenge by taxing authorities. In recent years, tax settlements, as well as state regulatory mechanisms with tax-related provisions (such as Idaho Power's October 2014 regulatory settlement stipulation with the IPUC), has significantly impacted IDACORP's and Idaho Power's results of operations. The outcome of ongoing and future income tax proceedings, or the state public utility commissions' treatment of those tax outcomes, could differ materially from the amounts IDACORP and Idaho Power record prior to conclusion of those proceedings, and the difference could negatively affect IDACORP's and Idaho Power's earnings and cash flows. Further, in some instances the treatment from a ratemaking perspective of any tax benefits could be different than IDACORP or Idaho Power anticipate or request from applicable state regulatory commissions, which could have a negative effect on their financial condition and results of operations.

Changes in accounting standards or rules may impact IDACORP's and Idaho Power's financial results and disclosures. The Financial Accounting Standards Board and the Securities and Exchange Commission may make changes to accounting standards that impact presentation and disclosures of financial condition and results of operations. Further, new accounting orders issued by the FERC could significantly impact IDACORP's and Idaho Power's reported financial condition. Idaho Power meets conditions under generally accepted accounting principles to reflect the impact of regulatory decisions in its financial statements and to defer certain costs as regulatory assets until those costs are collected in rates, and to defer some items as regulatory liabilities. If recovery of these amounts ceases to be probable, if Idaho Power determines that it no longer meets the criteria for applying regulatory accounting, or if accounting rules change to no longer provide for regulatory assets and liabilities, Idaho Power could be required to eliminate some or all of those regulatory assets or liabilities. Any of these circumstances could result in write-offs and have a material effect on IDACORP's and Idaho Power’s financial condition and results of operations.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Idaho Power's properties consist of the physical assets necessary to support its utility operations, which include generation, transmission, and distribution facilities, as well as coal assets that support one of its coal-fired generation plants. In addition to these physical assets, Idaho Power has rights-of-way and water rights that enable it to use its facilities. Idaho Power’s system is comprised of 17 hydroelectric generating plants located in southern Idaho and eastern Oregon, three natural gas-fired plants in southern Idaho, and interests in three coal-fired steam electric generating plants located in Wyoming, Nevada, and Oregon. As of December 31, 2015, the system also includes approximately 4,860 pole-miles of high-voltage transmission lines, 24 step-up transmission substations located at power plants, 24 transmission substations, 10 switching stations, 224 energized distribution substations (excluding mobile substations and dispatch centers), and approximately 27,092 pole-miles of distribution lines.

Idaho Power holds FERC licenses for all of its hydroelectric projects that are subject to federal licensing. Relicensing of Idaho Power's hydroelectric projects is discussed in Item 7 - MD&A – "Regulatory Matters – Relicensing of Hydroelectric Projects." Idaho Power's hydroelectric projects and other owned and co-owned generating facilities and their nameplate capacities are included in the table below.

Project	Nameplate Capacity (kW)[1]	License Expiration
Hydroelectric Projects:		
Properties Subject to Federal Licenses:		
Lower Salmon	60,000	2034
Bliss	75,000	2034
Upper Salmon	34,500	2034
Shoshone Falls	12,500	2034
CJ Strike	82,800	2034
Upper Malad - Lower Malad	21,770	2035
Brownlee - Oxbow - Hells Canyon (Hells Canyon Complex)	1,166,900	2005 [2]
Swan Falls	27,170	2042
American Falls	92,340	2025
Cascade	12,420	2031
Milner	59,448	2038
Twin Falls	52,897	2040
Other Hydroelectric:		
Clear Lakes - Thousand Springs	11,300	
Total Hydroelectric	1,709,045	
Steam and Other Generating Plants:		
Jim Bridger (coal-fired)[3]	770,501	
North Valmy (coal-fired)[3]	283,500	
Boardman (coal-fired)[3][4]	64,200	
Danskin (gas-fired)	270,900	
Langley Gulch (gas-fired)	318,452	
Bennett Mountain (gas-fired)	172,800	
Salmon (diesel-internal combustion)	5,000	
Total Steam and Other	1,885,353	
Total Generation	3,594,398	

(1) Actual generation capacity from a facility may be greater or less than the rated nameplate generation capacity.

(2) Licensed on an annual basis while the application for a new multi-year license is pending.

(3) Idaho Power's ownership interests are 33 percent for Jim Bridger, 50 percent for Valmy, and 10 percent for Boardman. Amounts shown represent Idaho Power's share.

(4) Pursuant to an Oregon Environmental Quality Commission plan and associated rules, the Boardman power plant is scheduled for cessation of coal-fired operations by December 31, 2020.

IDACORP's and Idaho Power's headquarters are located in Boise, Idaho. The corporate headquarters campus is comprised of approximately 306,000 square feet of owned office space. Excluding Idaho Power's power generation facilities and substations, Idaho Power owns an additional 907,000 square feet of office, warehouse, and industrial space to support its operations in Idaho and Oregon.

Idaho Power owns all of its interests in principal plants and other important units of real property, except for portions of certain projects licensed under the FPA and reservoirs and other easements. Substantially all of Idaho Power's property is subject to the lien of its Mortgage and Deed of Trust and the provisions of its project licenses. Idaho Power's property is subject to minor defects common to properties of such size and character that it believes do not materially impair the value to, or the use by, Idaho Power of such properties. Idaho Power considers its properties to be well-maintained and in good operating condition.

Through Idaho Energy Resources Co., Idaho Power owns a one-third interest in BCC and coal leases near the Jim Bridger generating plant in Wyoming from which coal is mined and supplied to the plant. Ida-West holds 50-percent interests in nine hydroelectric plants that have a total generating capacity of 45 MW. These plants are located in Idaho and California.

ITEM 3. LEGAL PROCEEDINGS

Refer to Note 10 – “Contingencies” to the consolidated financial statements included in this report.

ITEM 4. MINE SAFETY DISCLOSURES

Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Wall Street Reform and Consumer Protection Act and Item 104 of Regulation S-K (17 CFR 229.104) is included in Exhibit 95.1 of this report.

PART II

ITEM 5. MARKET FOR REGISTRANT’S COMMON EQUITY, RELATED STOCKHOLDER MATTERS, AND ISSUER PURCHASES OF EQUITY SECURITIES

IDACORP’s common stock, without par value, is traded on the New York Stock Exchange (NYSE). On February 12, 2016, there were 10,448 holders of record of IDACORP common stock and the closing stock price was $69.59 per share. The outstanding shares of Idaho Power’s common stock, $2.50 par value, are held by IDACORP and are not traded. IDACORP became the holding company of Idaho Power on October 1, 1998.

IDACORP and Idaho Power paid dividends of $97 million, $89 million, and $79 million in 2015, 2014, and 2013, respectively. The amount and timing of dividends paid on IDACORP’s common stock are within the discretion of IDACORP’s board of directors, subject to other restrictions. The board of directors reviews the dividend rate quarterly to determine its appropriateness in light of IDACORP’s current and long-term financial position and results of operations, capital requirements, rating agency requirements, contractual and regulatory restrictions, legislative and regulatory developments affecting the electric utility industry in general and Idaho Power in particular, competitive conditions, and any other factors the board of directors deems relevant. The ability of IDACORP to pay dividends on its common stock is dependent upon dividends paid to it by its subsidiaries, primarily Idaho Power. The IDACORP board of directors has a dividend policy for IDACORP that provides for a target long-term dividend payout ratio of between 50 and 60 percent of sustainable IDACORP earnings, with the flexibility to achieve that payout ratio over time and to adjust the payout ratio or to deviate from the target payout ratio from time to time based on the various factors that drive the board of director's dividend decisions. IDACORP's 2015 calendar year payout ratio was 50 percent. Notwithstanding the dividend policy adopted by IDACORP's board of directors, the dividends IDACORP pays remain in the discretion of the board of directors who, when evaluating the dividend amount, will take into account the foregoing factors, among others.

IDACORP's and Idaho Power's payment of dividends is subject to a number of restrictions. For information relating to those restrictions, see Note 6 - “Common Stock” to the consolidated financial statements included in this report.

The following table shows the reported high and low sales price of IDACORP’s common stock and dividends paid for 2015 and 2014 as reported by the NYSE:

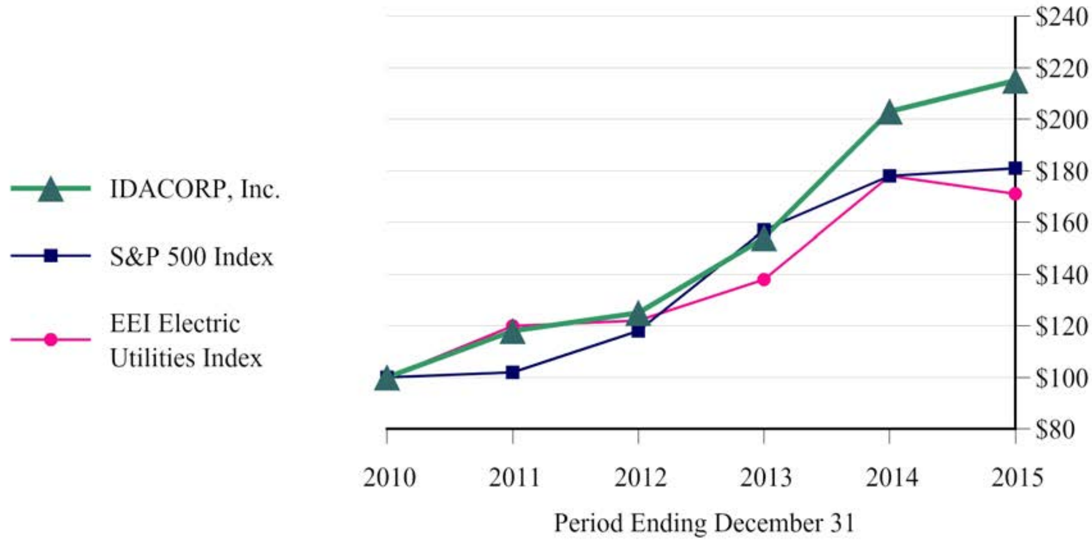
	2015			2014		
Quarter	High	Low	Dividends paid per share	High	Low	Dividends paid per share
1st	$ 70.48	$ 59.21	$ 0.47	$ 56.65	$ 50.21	$ 0.43
2nd	64.22	55.40	0.47	57.86	52.91	0.43
3rd	64.94	55.96	0.47	58.79	51.70	0.43
4th	70.33	63.38	0.51	70.05	53.39	0.47

IDACORP did not repurchase any shares of its common stock during the fourth quarter of 2015.

Performance Graph

The graph below shows a comparison of the five-year cumulative total shareholder return for IDACORP common stock, the S&P 500 Index, and the Edison Electric Institute (EEI) Electric Utilities Index. The data assumes that $100 was invested on December 31, 2010, with beginning-of-period weighting of the peer group indices (based on market capitalization) and monthly compounding of returns.

Comparison of Cumulative Total Return
$100 Invested December 31, 2010



Source: Bloomberg and EEI

	2010	2011	2012	2013	2014	2015
IDACORP	$ 100.00	$ 118.25	$ 124.96	$ 154.34	$ 203.17	$ 215.24
S&P 500	100.00	102.08	118.39	156.70	178.10	180.56
EEI Electric Utilities Index	100.00	119.99	122.49	138.42	178.44	171.48

The foregoing performance graph and data shall not be deemed “filed” as part of this Form 10-K for purposes of Section 18 of the Securities Exchange Act of 1934 or otherwise subject to the liabilities of that section and shall not be deemed incorporated by reference into any other filing of IDACORP or Idaho Power under the Securities Act of 1933 or the Securities Exchange Act of 1934, except to the extent IDACORP or Idaho Power specifically incorporates it by reference into such filing.

ITEM 6. SELECTED FINANCIAL DATA

IDACORP, Inc.
SUMMARY OF OPERATIONS
(thousands of dollars, except per share amounts and statistics)

	2015	2014	2013	2012	2011
Operating revenues	$1,270,289	$1,282,524	$1,246,214	$1,080,662	$1,026,756
Operating income	282,097	253,696	291,742	242,602	155,352
Net income attributable to IDACORP, Inc.	194,679	193,480	182,417	173,014	169,981
Diluted earnings per share	3.87	3.85	3.64	3.46	3.43
Dividends declared per share	1.92	1.76	1.57	1.37	1.20
Financial Condition:					
Total assets [1]	$6,023,314	$5,701,037	$5,347,380	$5,274,147	$4,908,326
Long-term debt (including current portion) [1]	$1,726,474	$1,599,686	$1,599,139	$1,520,553	$1,471,621
Financial Statistics:					
Times interest charges earned:					
Before tax[2]	3.61	3.38	3.87	3.41	2.48
After tax[3]	3.12	3.19	3.06	3.02	3.00
Book value per share[4]	$ 40.88	$ 38.85	$ 36.84	$ 34.73	$ 32.76
Market-to-book ratio [5]	166%	170%	141%	125%	129%
Payout ratio [6]	50%	46%	43%	40%	35%
Return on year-end common equity [7]	9.5%	9.9%	9.9%	9.9%	10.4%

(1) Adjusted to reflect the adoption of ASU 2015-03. See Note 1 to the consolidated financial statements included in this report.

The financial statistics listed above are calculated in the following manner:

(2) The sum of interest on long-term debt, other interest expense excluding AFUDC credits, and income before income taxes divided by the sum of interest on long-term debt and other interest expense excluding AFUDC credits.

(3) The sum of interest on long-term debt, other interest expense excluding AFUDC credits, and income from continuing operations divided by the sum of interest on long-term debt and other interest expense excluding AFUDC credits.

(4) Total equity, excluding non-controlling interests, at the end of the year divided by shares outstanding at the end of the year.

(5) The closing price of IDACORP stock on the last day of the year divided by the book value per share, which is described in footnote (4) above.

(6) Dividends paid per common share divided by diluted earnings per share.

(7) Net income attributable to IDACORP, Inc. divided by total equity, excluding non-controlling interests, at the end of the year.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

In Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) in this report, the general financial condition and results of operations for IDACORP, Inc. and its subsidiaries (collectively, IDACORP) and Idaho Power Company and its subsidiary (collectively, Idaho Power) are discussed. While reading the MD&A, please refer to the accompanying consolidated financial statements of IDACORP and Idaho Power. Also refer to "Cautionary Note Regarding Forward-Looking Statements" and Part I - Item 1A - "Risk Factors" in this report for important information regarding forward-looking statements made in this MD&A and elsewhere in this report.

In the MD&A, MWh and dollar amounts in tables, other than earnings per share, are in thousands unless otherwise indicated.

INTRODUCTION

IDACORP is a holding company formed in 1998 whose principal operating subsidiary is Idaho Power. IDACORP's common stock is listed and trades on the New York Stock Exchange under the trading symbol "IDA". Idaho Power is an electric utility whose rates and other matters are regulated by the Idaho Public Utility Commission (IPUC), Public Utility Commission of Oregon (OPUC), and Federal Energy Regulatory Commission (FERC). Idaho Power generates revenues and cash flows primarily from the sale and distribution of electricity to customers in its Idaho and Oregon service territories, as well as from the wholesale sale and transmission of electricity. Idaho Power experiences its highest retail energy sales during the summer irrigation and cooling season, with a lower peak in the winter that generally results from heating demand. Idaho Power's rates are established through regulatory proceedings that affect its ability to recover its costs and the potential to earn a return on its investment.

Idaho Power is the parent of Idaho Energy Resources Co. (IERCo), a joint venturer in Bridger Coal Company (BCC), which mines and supplies coal to the Jim Bridger generating plant owned in part by Idaho Power. IDACORP's other subsidiaries include IDACORP Financial Services, Inc. (IFS), an investor in affordable housing and other real estate investments; Ida-West Energy Company, an operator of small hydroelectric generation projects that satisfy the requirements of the Public Utility Regulatory Policies Act of 1978 (PURPA); and IDACORP Energy Services Co., which is the former limited partner of, and successor by merger to, IDACORP Energy L.P., a marketer of energy commodities that wound down operations in 2003.

EXECUTIVE OVERVIEW

Management's Outlook

Idaho Power continues to see positive growth in its customer count and associated positive impacts on Idaho Power's revenue. To encourage responsible and sustainable growth, and as part of its planning for the future, Idaho Power actively participates in and supports state and local economic development initiatives. At the same time that Idaho Power pursues customer growth, it must also plan for that growth. Idaho Power's recently completed 2015 Integrated Resource Plan (IRP) assumed growth in customers for the next 20 years and seeks to plan for the infrastructure that will support the anticipated growth and allow Idaho Power to continue to provide reliable, fair-priced electric power to its customers. To that end, Idaho Power's noteworthy capital projects include the replacement of aging assets, upgrades to generation plants, a multi-year plan for replacement of underground conductor, ongoing system upgrades, and continued progress on permitting the Boardman-to-Hemingway and Gateway West 500-kV transmission lines. As of the date of this report, Idaho Power estimates total capital expenditures of nearly $1.5 billion over the next five years.

Idaho Power operates within what it believes to be a constructive regulatory framework, achieved through general rate cases, subject-specific rate filings, tariff riders, and cost recovery mechanisms that share risks and benefits with Idaho Power's customers. To further complement these efforts, Idaho Power has also been focusing on controlling power supply, operating, maintenance, and capital costs through process review and improvement initiatives, and by empowering employees to identify new means to reduce costs, increase efficiencies, and enhance individual and enterprise performance for the benefit of IDACORP's shareholders, Idaho Power's customers, and other stakeholders. As Idaho Power's base rates were most recently reset in a general rate case in 2012, during 2016 Idaho Power plans to evaluate the desirability of filing an application for a general rate change in Idaho or Oregon.

Separately, during 2015 IDACORP continued to make meaningful progress toward its target dividend payout ratio of between 50 and 60 percent of sustainable IDACORP earnings, which expanded on the progress made in prior years. From 2012 through

2015, IDACORP's board of directors approved a collective 70 percent increase in the quarterly dividend, from $0.30 to $0.51 per share.

2015 Accomplishments and 2016 Initiatives

IDACORP’s business strategy emphasizes Idaho Power as IDACORP’s core business. For the past several years, Idaho Power has been executing its three-part strategy of responsible planning, responsible development and protection of resources, and responsible energy use to ensure adequate energy supplies. This strategy is described in Part I, Item 1 - "Business" of this report. Examples of IDACORP's and Idaho Power's achievements and recognitions during 2015 under its three-part business strategy include:

- achieved net income growth for an eighth consecutive year;
- increased IDACORP's quarterly common stock dividend from $0.47 per share to $0.51 per share;
- executed on business optimization initiatives, focusing on improving operations and controlling expenditures;
- made continued progress toward the permitting of the Boardman-to-Hemingway and Gateway West 500-kV transmission projects;
- achieved its goal to reduce average CO_2 emissions intensity by 10 to 15 percent below 2005 emissions for the period from 2010 through 2015;
- achieved the highest rolling 12-month customer relationship index score (Idaho Power's internal measure of customer satisfaction) ever recorded by the company; and
- improved Idaho Power's ranking from 17 to 11 in the annual "40 Best Energy Companies" list published by *Public Utilities Fortnightly*.

For 2016, in addition to its specific infrastructure and regulatory projects noted above, IDACORP and Idaho Power have established a number of organizational initiatives, including the following:

- make progress on three core focuses for 2016—improving Idaho Power's core business, growing revenues, and enhancing the brand and positioning the company for the future;
- continue to enhance and promote Idaho Power’s safety culture;
- grow financial strength by supporting business development in our service territory while actively managing costs;
- continue progress toward IDACORP’s target dividend payout ratio;
- pursue responsible investments that address customer growth while improving reliability, enhancing Idaho Power customers’ experience, increasing shareholder value, and managing carbon impacts; and
- integrate new renewable generation resources into Idaho Power’s grid and explore intra-hour market opportunities to help achieve greater reliability and improve system dispatch.

Overview of General Factors and Trends Affecting Results of Operations and Financial Condition

IDACORP's and Idaho Power's results of operations and financial condition are affected by a number of factors, and the impact of those factors is discussed in more detail later in this MD&A. To provide context for the discussion elsewhere in this report, some of the more notable factors include the following:

- ***Regulation of Rates and Cost Recovery:*** The price that Idaho Power is authorized to charge for its electric and transmission service is a critical factor in determining IDACORP's and Idaho Power's results of operations and financial condition. Those rates are established by state regulatory commissions and the FERC, and are intended to allow Idaho Power an opportunity to recover its expenses and earn a reasonable return on investment. Because of the significant impact of ratemaking decisions, and in furtherance of its goal of advancing a purposeful regulatory strategy, Idaho Power has focused on timely recovery of its costs through filings with the company's regulators, working to put in place innovative regulatory mechanisms, and on the prudent management of expenses and investments. Idaho Power has a regulatory settlement stipulation in Idaho that remains in effect during 2016. That stipulation includes provisions for the accelerated amortization of certain tax credits to help achieve a minimum 9.5 percent return on year-end equity in the Idaho jurisdiction (Idaho ROE). Also during 2016, Idaho Power will continue to assess its need to file a general rate case to reset base rates.

- ***Rate Base Growth and Infrastructure Investment:*** As noted above, the rates established by the IPUC and OPUC are determined so as to provide an opportunity for Idaho Power to recover authorized operating expenses and earn a reasonable return on “rate base.” Rate base is generally determined by reference to the original cost (net of accumulated depreciation) of utility plant in service, subject to various adjustments for deferred taxes and other items.

Over time, rate base is increased by additions to utility plant in service and reduced by depreciation and retirement of utility plant and write-offs as authorized by the IPUC and OPUC. In recent years, Idaho Power has been pursuing significant enhancements to its utility infrastructure, including major ongoing transmission projects such as the Boardman-to-Hemingway and Gateway West projects, in an effort to ensure an adequate supply of electricity, to provide service to new customers, and to maintain system reliability. Idaho Power's existing hydroelectric and thermal generation facilities also require continuing upgrades and component replacement, and the company is undertaking a significant relicensing effort for the Hells Canyon Complex (HCC), its largest hydroelectric generation resource. Idaho Power expects to include completed capital projects in its next general rate case or, in circumstances where appropriate, a single-issue rate case for individual projects with a significant capital cost. Depending on the outcome of the regulatory process and items such as the rate of return authorized by the IPUC and OPUC, this growth in rate base has the potential to increase Idaho Power's revenues and earnings.

- ***Economic Conditions:*** Economic conditions impact consumer demand for electricity and revenues, collectability of accounts, the volume of off-system sales, and the need to construct and improve infrastructure, purchase power, and implement programs to meet customer load demands. In recent years, Idaho Power has seen growth in the number of customers in its service area—in 2015 its customer count grew by 1.8 percent, and employment in Idaho Power's service area grew by approximately 4.9 percent in 2015 based on Idaho Department of Labor preliminary December 2015 data. Idaho Power expects that the number of customers will continue to increase in the foreseeable future. To help encourage growth, Idaho Power has in recent years undertaken efforts to promote economic development and attract industrial and commercial customers to its service area.

- ***Weather Conditions:*** Weather and agricultural growing conditions have a significant impact on energy sales and the seasonality of those sales. Relatively low and high temperatures result in greater energy use for heating and cooling, respectively. During the agricultural growing season, which in large part occurs during the second and third quarters, irrigation customers use electricity to operate irrigation pumps, and weather conditions can impact the timing and degree of use of those pumps. Idaho Power also has tiered rates and seasonal rates, which contribute to increased revenues during higher-load periods, most notably during the third quarter of each year when overall customer demand is highest. Further, as Idaho Power's hydroelectric facilities comprise nearly one-half of Idaho Power's nameplate generation capacity, precipitation levels impact the mix of Idaho Power's generation resources. When hydroelectric generation is reduced, Idaho Power must rely on more expensive generation sources and purchased power. When favorable hydroelectric generating conditions exist for Idaho Power, they also may exist for other Pacific Northwest hydroelectric facility operators, lowering regional wholesale market prices and impacting the revenue Idaho Power receives from off-system sales of its excess power. Much of the adverse or favorable impact of this volatility is addressed through the Idaho and Oregon power cost adjustment (PCA) mechanisms.

- ***Mitigation of Impact of Fuel and Purchased Power Expense:*** In addition to hydroelectric generation, Idaho Power relies significantly on coal and natural gas to fuel its generation facilities and power purchases in the wholesale markets. Fuel costs are impacted by electricity sales volumes, the terms of contracts for fuel, Idaho Power's generation capacity, the availability of hydroelectric generation resources, transmission capacity, energy market prices, and Idaho Power's hedging program for managing fuel costs. Recently, low natural gas prices have made operation of Idaho Power's natural gas power plants more economical, resulting in increased operation of those plants and lessened operation of coal-fired plants. Purchased power costs are impacted by the terms of contracts for purchased power, the rate of expansion of alternative energy generation sources such as wind or solar energy, and wholesale energy market prices. Idaho Power is required by law to purchase power from some PURPA generation projects at a specified price regardless of the then-current load demand or wholesale energy market prices. This increases the likelihood that Idaho Power will at times be required to reduce output from its lower-cost hydroelectric and fossil fuel-fired generation resources and may be required to sell in the wholesale power market the power it purchases from PURPA projects at a significant loss, which results in increased customer rates. The Idaho and Oregon PCA mechanisms mitigate in large part the potential adverse impacts of fluctuations in power supply costs to Idaho Power, including all of the Idaho-jurisdiction PURPA power purchase costs.

- ***Regulatory and Environmental Compliance Costs:*** Idaho Power is subject to extensive federal and state laws, policies, and regulations, as well as regulatory actions and audits by agencies and quasi-governmental agencies, including the FERC and the North American Electric Reliability Corporation. Compliance with these requirements directly influences Idaho Power's operating environment and affects Idaho Power's operating costs. Environmental laws and regulations, in particular, may increase the cost of operating generation plants and constructing new facilities, require that Idaho Power install additional pollution control devices at existing generating plants, or require that Idaho Power cease operating certain generation plants. For instance, the Boardman coal-fired power plant, in which Idaho

Power owns a 10-percent interest, is scheduled to cease coal-fired operations by the end of 2020, a decision driven in large part by the substantial cost of environmental controls required by existing regulations. Idaho Power expects to spend a considerable amount on environmental compliance and controls in the next decade.

- ***Water Management and Relicensing of the Hells Canyon Hydroelectric Project (HCC):*** Because of Idaho Power's reliance on stream flow in the Snake River and its tributaries, Idaho Power participates in numerous proceedings and venues that may affect its water rights, seeking to preserve the long-term availability of its rights for its hydroelectric projects. Also, Idaho Power is involved in renewing its long-term federal license for the HCC, its largest hydroelectric generation source. Given the number of parties and issues involved, Idaho Power's relicensing costs have been and will continue to be substantial. Idaho Power cannot currently determine the terms of, and costs associated with, any resulting long-term license.

Summary of 2015 Financial Results

The following is a summary of Idaho Power's net income, net income attributable to IDACORP, and IDACORP's earnings per diluted share for the years ended December 31, 2015, 2014, and 2013 (in thousands, except earnings per share amounts):

	Year Ended December 31,		
	2015	**2014**	**2013**
Idaho Power net income	$ 190,983	$ 189,387	$ 176,741
Net income attributable to IDACORP, Inc.	$ 194,679	$ 193,480	$ 182,417
Average outstanding shares – diluted (000’s)	50,292	50,199	50,126
IDACORP, Inc. earnings per diluted share	$ 3.87	$ 3.85	$ 3.64

The table below provides a reconciliation of net income attributable to IDACORP, Inc. for year ended December 31, 2015 to the year ended December 31, 2014 (items are in millions and are before tax unless otherwise noted):

Net income attributable to IDACORP, Inc. - December 31, 2014		**$ 193.5**
Change in Idaho Power net income:		
Customer growth, net of associated power supply costs	10.3	
Usage per customer, net of associated power supply costs	(6.7)	
Change in FCA revenues due to sales volumes and mechanism change	12.7	
Depreciation expense and property taxes	(6.2)	
Rent from electric property, wheeling and other revenue	3.0	
Other operating and maintenance expenses	(4.2)	
Change in Idaho Power operating income prior to sharing mechanisms	8.9	
Change in operating income as a result of sharing mechanisms	21.5	
Change in Idaho Power operating income	30.4	
Non-operating income and expenses	(0.4)	
Change in income tax benefit related to first mortgage bond redemption costs	7.2	
Change in income tax expense due to cumulative impact of tax method change recorded in 2014	(24.5)	
Other change in income tax expense	(11.1)	
Total increase in Idaho Power net income		1.6
Other changes (net of tax)		(0.4)
Net income attributable to IDACORP, Inc. - December 31, 2015		**$ 194.7**

IDACORP's 2015 net income was nearly equivalent to its 2014 net income. However, there were several notable differences in the drivers of each year's results. Idaho Power's operating income, excluding the impact of the sharing mechanisms under Idaho regulatory settlement stipulations, increased $8.9 million for 2015 compared with 2014. Increased sales volumes associated with continued growth in the number of Idaho Power customers increased operating income by $10.3 million, though this was partially offset by a $6.7 million decrease from reduced overall usage per customer. Increases in depreciation and property taxes, and other operating and maintenance expenses (which include labor-related expenses), combined to decrease operating income by $10.4 million in 2015 when compared with 2014. Modifications were made to Idaho Power's FCA mechanism for 2015 to track fluctuations in residential and small commercial sales associated with actual weather conditions, as opposed to normalized weather conditions under the 2014 FCA mechanism. The FCA mechanism modification, combined with lower sales per customer, provided a $12.7 million benefit to operating income in 2015 compared with 2014.

Additionally, two income tax matters had a significant impact on the comparative results. Income taxes in 2015 reflect a $7.2 million flow-through impact of a tax deductible make-whole premium Idaho Power paid upon early redemption of long-term debt during 2015. Income tax expense in 2014 included a $24.5 million benefit from the cumulative effect of a tax method change made in that year.

Further, during 2015 Idaho Power recorded a total of $3.2 million as a provision against current revenue related to an October 2014 Idaho regulatory settlement stipulation that requires sharing with Idaho customers of a portion of 2015 earnings when Idaho Power's Idaho ROE exceeds 10.0 percent. By contrast, during 2014 under a prior, yet similar, Idaho regulatory settlement stipulation, Idaho Power recorded $24.7 million for sharing with Idaho customers. Of that amount, $16.7 million was recorded as additional pension expense and $8.0 million was recorded as a provision against current revenues to be refunded to customers through a future rate reduction. From 2011 to 2015, Idaho Power has shared over $120 million with customers through settlement stipulations.

RESULTS OF OPERATIONS

This section of the MD&A takes a closer look at the significant factors that affected IDACORP’s and Idaho Power’s earnings. In this analysis, the results for 2015 are compared with 2014 and the results for 2014 are compared with 2013.

Utility Operations

The table below presents Idaho Power’s energy sales and supply (in thousands of MWh) for the last three years.

	Year Ended December 31,		
	2015	**2014**	**2013**
General business sales	14,265	14,092	14,619
Off-system sales	1,254	2,220	1,683
Total energy sales	15,519	16,312	16,302
Hydroelectric generation	5,910	6,170	5,656
Coal generation	4,676	5,851	6,327
Natural gas and other generation	2,076	1,175	1,576
Total system generation	12,662	13,196	13,559
Purchased power	3,792	4,153	3,902
Line losses	(935)	(1,037)	(1,159)
Total energy supply	15,519	16,312	16,302

Sales Volume and Generation: In 2015, general business sales volume increased by 1 percent compared with the prior year, as the positive sales volume impact of customer growth exceeded reduced usage from moderate weather and energy efficiency measures. Off-system sales volume decreased by 44 percent in 2015 as decreases in output from hydroelectric generation resources reduced the amount of surplus power available for off-system sales. Also, more favorable wholesale market conditions in 2014 provided more opportunities for Idaho Power to operate its non-hydroelectric generation facilities for off-system sales during 2014 than in 2015.

Generation from Idaho Power's hydroelectric plants declined 4 percent in 2015 compared with 2014 due largely to below-average stream flows. The below-average hydroelectric generation during 2013 through 2015 resulted from relatively low snow pack and spring season run-off during the three-year period. At Idaho Power's thermal plants, coal-fired generation decreased while natural gas-fired generation increased, as low natural gas prices made natural gas-fired plants more economical to run in 2015 than in 2014.

The financial impacts of fluctuations in off-system sales, purchased power, fuel expense, and other power supply-related expenses are mitigated by the Idaho and Oregon PCA mechanisms, as further discussed later in this report.

***General Business Revenues*:** The table below presents Idaho Power's general business revenues, MWh sales, and number of customers for the last three years.

	Year Ended December 31,		
	2015	**2014**	**2013**
Revenue			
Residential	$ 512,068	$ 500,195	$ 513,914
Commercial	306,178	299,462	281,009
Industrial	182,254	182,675	165,941
Irrigation	164,403	158,654	159,242
Total	1,164,903	1,140,986	1,120,106
Provision for sharing	(3,159)	(7,999)	(7,602)
Deferred revenue related to HCC relicensing AFUDC[(1)]	(10,706)	(10,706)	(10,776)
Total general business revenues	$ 1,151,038	$ 1,122,281	$ 1,101,728
Volume of Sales (MWh)			
Residential	4,977	4,965	5,365
Commercial	4,045	3,944	3,975
Industrial	3,196	3,217	3,182
Irrigation	2,047	1,966	2,097
Total MWh sales	14,265	14,092	14,619
Number of customers at year-end			
Residential	436,102	428,294	422,188
Commercial	68,352	67,522	66,734
Industrial	118	121	115
Irrigation	20,293	19,826	19,398
Total customers	524,865	515,763	508,435

(1) Idaho Power is collecting approximately $10.7 million annually in the Idaho jurisdiction for AFUDC on HCC construction work in progress, but is deferring revenue recognition of the amounts collected until the license is issued and the accumulated license costs are placed in service.

Changes in rates, changes in customer demand, and changes in FCA revenues are typically the primary causes of fluctuations in general business revenue from period to period. See "Regulatory Matters" in this MD&A for a list of rate changes implemented over the last three years. The primary influences on changes in customer demand for electricity are weather, economic conditions, and energy efficiency. Extreme temperatures increase sales to customers who use electricity for cooling and heating, while moderate temperatures decrease sales. Precipitation levels and the timing of precipitation during the agricultural growing season also affect sales to customers who use electricity to operate irrigation pumps. For purposes of illustration and comparison, Boise, Idaho weather-related information for the last three years is presented in the table that follows.

	Year Ended December 31,			
	2015	**2014**	**2013**	**Normal**
Heating degree-days[(1)]	4,694	4,976	6,032	5,556
Cooling degree-days[(1)]	1,280	1,129	1,320	942

(1) Heating and cooling degree-days are common measures used in the utility industry to analyze the demand for electricity and indicate when a customer would use electricity for heating and air conditioning. A degree-day measures how much the average daily temperature varies from 65 degrees. Each degree of temperature above 65 degrees is counted as one cooling degree-day, and each degree of temperature below 65 degrees is counted as one heating degree-day. While Boise, Idaho weather conditions are not necessarily representative of weather conditions throughout Idaho Power's service area, the greater Boise area has the majority of Idaho Power's customers.

Idaho Power's rate structure provides for higher rates during the summer when system loads are at their highest, and includes tiers such that rates increase as a customer's consumption level increases. These seasonal and tiered rate structures contribute to seasonal fluctuations in revenues and earnings.

General Business Revenues - 2015 Compared with 2014: General business revenue increased $28.8 million in 2015 compared with 2014. The factors affecting general business revenues included the following:

- Rates. Two rate changes impacted general business revenue—an Idaho PCA rate increase effective June 1, 2014, and an Idaho PCA rate decrease effective June 1, 2015, both described in Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report. Overall, rate changes combined to decrease general business revenue by $2.2 million in 2015.

- Usage. Lower usage per customer in 2015, primarily driven by the impact of more moderate winter weather on residential customer usage, as well as energy efficiency, decreased general business revenue by $0.7 million. Residential usage per customer was 1.4 percent lower in 2015.

- Customers. Customer growth increased general business revenue by $14.1 million. Customer growth from 2014 to 2015 was 1.8 percent.

- Sharing. General business revenue was impacted by Idaho Power's revenue sharing mechanism. This mechanism is associated with Idaho regulatory settlement agreements that provide for the sharing with customers of a portion of Idaho-jurisdiction earnings exceeding a 10.0 percent Idaho ROE. The impact of this mechanism is partially recorded as a reduction to general business revenue. Reductions of $3.2 million and $8.0 million were recorded in 2015 and 2014, respectively, resulting in a net increase to general business revenue of $4.8 million in 2015.

- FCA Revenue. FCA mechanism revenues increased $12.7 million compared with 2014, including the impacts of weather and of modifications made to the mechanism by the IPUC effective January 1, 2015. The modifications to the FCA mechanism are described in more detail in "Regulatory Matters" in this MD&A and in Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report.

General Business Revenues - 2014 Compared with 2013: General business revenue increased $20.6 million in 2014 compared with 2013. The factors affecting general business revenues included the following:

- Rates. Rate changes, primarily associated with increased power supply costs, combined to increase general business revenue by $64.8 million. The revenue impact of the rate changes was partially offset by associated changes in operating expenses—Idaho PCA amortization expense increased $42.8 million in 2014 due to the change in the corresponding Idaho PCA true-up rates.

- Usage. Lower usage per customer, primarily driven by the impact of more moderate weather during 2014 on residential customer usage, as well as energy efficiency, decreased general business revenue by $55.7 million. Residential usage per customer was 9.1 percent lower in 2014.

- Customers. Continued customer growth partially offset the decrease in overall MWh sales, increasing revenue by $11.9 million. Customer growth from 2013 to 2014 was 1.4 percent.

- Sharing. The overall increase in general business revenue was impacted by Idaho Power's revenue sharing mechanism. This mechanism, which was in place for 2012 through 2014, is associated with the December 2011 Idaho regulatory settlement agreement that provides for the sharing with customers of a portion of Idaho-jurisdiction earnings exceeding a 10.0 percent Idaho ROE. The impact of this mechanism is partially recorded as a reduction to general business revenue. Reductions of $8.0 million and $7.6 million were recorded in 2014 and 2013, respectively, resulting in a net decrease to general business revenue of $0.4 million in 2014.

Off-System Sales: Off-system sales consist primarily of long-term sales contracts and opportunity sales of surplus system energy. The following table presents Idaho Power's off-system sales for the last three years:

	Year Ended December 31,		
	2015	**2014**	**2013**
Revenue	$ 30,887	$ 77,165	$ 54,473
MWh sold	1,254	2,220	1,683
Revenue per MWh	$ 24.63	$ 34.76	$ 32.37

Off-System Sales - 2015 Compared with 2014: Off-system sales revenue decreased by $46.3 million, or 60 percent, in 2015. Off-system sales volumes decreased 44 percent, as 2014 sales benefited from more favorable market conditions, at times, for selling power off-system. The average price of off-system sales transactions in 2015 was 29 percent lower than 2014, indicative of generally lower market prices in 2015. Decreases in output from hydroelectric resources and an increase in overall load due to customer growth also reduced the amount of surplus power available for sale off-system during 2015.

Off-System Sales - 2014 Compared with 2013: Off-system sales revenue increased by $22.7 million, or 42 percent, in 2014 as a result of favorable market conditions, at times, for selling power off-system. Off-system sales volumes also benefitted from greater amounts of surplus system energy resulting from slightly lower system loads and increased hydroelectric generation and PURPA power purchases.

Other Revenues: The table below presents the components of other revenues for the last three years:

	Year Ended December 31,		
	2015	**2014**	**2013**
Transmission services and other	$ 55,048	$ 52,051	$ 51,260
Energy efficiency	30,532	27,154	35,637
Total other revenues	$ 85,580	$ 79,205	$ 86,897

Other Revenues - 2015 Compared with 2014: Other revenues increased $6.4 million, or 8 percent, in 2015. The increases in 2015 were primarily the result of increased electricity transmission (wheeling) volumes and greater customer participation in energy efficiency programs. Most energy efficiency activities are funded through a rider mechanism on customer bills. Energy efficiency program expenditures funded through the rider are reported as an operating expense with an equal amount of revenues recorded in other revenues, resulting in no net impact on earnings.

Other Revenues - 2014 Compared with 2013: Other revenues decreased $7.7 million in 2014, resulting primarily from an order issued by the IPUC in the prior year that allowed Idaho Power to recover custom efficiency program incentive payments made between January 1, 2011 and June 1, 2013, through the energy efficiency rider. Based on the order, $14.3 million of other revenue (as well as energy efficiency program expense) was recognized in the second quarter of 2013. Partially offsetting the impact of this order from the IPUC was higher utilization of energy efficiency programs when compared with 2013.

Purchased Power: The table below presents Idaho Power's purchased power expenses and volumes for the last three years.

	Year Ended December 31,		
	2015	2014	2013
Expense			
PURPA contracts	$ 131,340	$ 144,617	$ 131,338
Other purchased power (including wheeling)	88,430	92,071	85,038
Demand response incentive payments	6,701	7,940	4,203
Total purchased power expense	$ 226,471	$ 244,628	$ 220,579
MWh purchased			
PURPA contracts	2,008	2,286	2,127
Other purchased power	1,784	1,867	1,775
Total MWh purchased	3,792	4,153	3,902
Cost per MWh from PURPA contracts	$ 65.41	$ 63.26	$ 61.75
Cost per MWh from other purchased power	$ 49.57	$ 49.31	$ 47.91
Weighted average - all sources (excluding demand response incentive payments)	$ 57.96	$ 56.99	$ 55.45

The purchased power cost per MWh often exceeds the off-system sales revenue per MWh because Idaho Power generally needs to purchase more power during heavy load periods than during light load periods, and conversely has less energy available for off-system sales during heavy load periods than light load periods. Market energy prices are typically higher during heavy load periods than during light load periods. Also, in accordance with Idaho Power's risk management policy, Idaho Power may purchase or sell energy several months in advance of anticipated delivery. The regional energy market price is dynamic and additional energy purchase or sale transactions that Idaho Power makes at current market prices may be noticeably different than the advance purchase or sale transaction prices. Most of the non-PURPA purchased power and substantially all of the PURPA power purchase costs are recovered through base rates and Idaho Power's PCA mechanisms.

Purchased Power - 2015 Compared with 2014: Purchased power expense decreased $18.2 million, or 7 percent, in 2015. The decrease was due primarily to reduced volumes purchased from both PURPA and non-PURPA sources. Volume decreases were partially offset by increases in average prices.

Purchased Power - 2014 Compared with 2013: Purchased power expense increased $24.0 million, or 11 percent, in 2014, mostly resulting from an increase in generation provided by PURPA wind contracts when compared with 2013. In addition, wholesale gas and electricity market conditions warranted third-party power purchases to serve system load at times rather than dispatching Idaho Power-owned thermal resources. Finally, the increases in demand response program incentive payments primarily relate to the temporary cessation of some of these programs during 2013, which were reinstated for 2014.

Fuel Expense: The table below presents Idaho Power's fuel expenses and thermal generation for the last three years.

	Year Ended December 31,		
	2015	2014	2013
Expense			
Coal [(1)]	$ 131,286	$ 156,172	$ 160,277
Natural gas and other thermal	54,945	45,069	54,205
Total fuel expense	$ 186,231	$ 201,241	$ 214,482
MWh generated			
Coal [(1)]	4,676	5,851	6,327
Natural gas and other thermal	2,076	1,175	1,576
Total MWh generated	6,752	7,026	7,903
Cost per MWh - Coal	$ 28.08	$ 26.69	$ 25.33
Cost per MWh - Natural gas and other thermal	26.47	38.36	34.39
Weighted average, all sources	$ 27.58	$ 28.64	$ 27.14

(1) 2015 excludes 147 MWh of generation from the Jim Bridger power plant for which costs were capitalized during feasibility testing of capital projects under contemplation.

Most fuel supply contracts are subject to changes in published indexes that are closely related to materials and supplies, labor, and diesel costs. In addition to commodity (variable) costs, both natural gas and coal expense include costs that are more fixed in nature for items such as capacity charges, transportation, and fuel handling. Period to period variances in fuel expense per MWh are noticeably impacted by these fixed charges when generation output is substantially different between the periods.

Fuel Expense - 2015 Compared with 2014: In 2015, fuel expense decreased $15.0 million, or 7 percent, compared with 2014, due principally to decreased output from coal-fired steam plants during 2015 combined with lower regional natural gas prices for fuel used at the natural gas-fired steam plants. Overall generation decreased 4 percent due to lower system loads and lower wholesale energy prices. The expense per MWh for natural gas decreased approximately 30 percent in 2015 compared to 2014. These lower natural gas prices led to a shift of generation from coal-fired steam plants to natural gas-fired steam plants.

Fuel Expense - 2014 Compared with 2013: In 2014, fuel expense decreased $13.2 million, or 6 percent, compared with 2013, due principally to decreased output from the natural gas-fired steam plants during 2014, resulting from lower system load demands and increased generation provided by facilities under PURPA contracts. The coal-fired steam plants were also operated less in 2014 when compared with 2013, as higher hydroelectric generation enabled lower utilization of the coal-fired steam plants to serve system load requirements. Partially offsetting these decreases were higher commodity costs when compared with 2013.

***PCA Mechanisms*:** Idaho Power's power supply costs (primarily purchased power and fuel, less off-system sales) can vary significantly from year to year. Volatility of power supply costs arises from factors such as weather conditions, wholesale market prices and volumes of power purchased and sold in the wholesale markets, Idaho Power's hydroelectric and thermal generation volumes and fuel costs, generation plant availability, and retail loads. To address the volatility of power supply costs, Idaho Power's PCA mechanisms in the Idaho and Oregon jurisdictions allow Idaho Power to recover from or refund to customers most of the fluctuations in power supply costs. In the Idaho jurisdiction, the PCA includes a cost or benefit sharing ratio that allocates the deviations in net power supply expenses between customers (95 percent) and the company (5 percent), with the exception of PURPA power purchases and demand-response program incentives, which are allocated 100 percent to customers. Because of the PCA mechanisms, the primary financial impacts of power supply cost variations is that cash is paid out but recovery from customers does not occur until a future period, or cash that is collected is refunded to customers in a future period, resulting in fluctuations in operating cash flows from year to year. The table that follows presents the components of the Idaho and Oregon PCA mechanisms for the last three years.

	Year Ended December 31,		
	2015	**2014**	**2013**
Idaho power supply cost deferrals	$ (35,802)	$ (48,104)	$ (67,127)
Amortization of prior year authorized balances	52,568	70,339	27,590
Total power cost adjustment expense	$ 16,766	$ 22,235	$ (39,537)

The power supply deferrals represent the portion of the power supply cost fluctuations deferred under the PCA mechanisms. When actual power supply costs are higher than the amount forecasted in PCA rates most of the difference is deferred. The amortization of the prior year’s balances represents the offset to the amounts being collected or refunded in the current PCA year that were deferred or accrued in the prior PCA year (the true-up component of the PCA).

PCA Mechanisms - 2015 Compared with 2014: Actual net power supply cost deferrals decreased in 2015 relative to 2014, a change of $12.3 million—from $48.1 million to $35.8 million. Power supply costs collected through base rates increased on June 1, 2014, resulting in less costs needing to be recovered through the PCA mechanism since that time. The $52.6 million of amortization offsets the collection from customers of prior years' deferrals.

PCA Mechanisms - 2014 Compared with 2013: Actual net power supply cost deferrals decreased in 2014 relative to 2013, a change of $19.0 million—from $67.1 million to $48.1 million. Power supply costs collected through base rates increased on June 1, 2014, resulting in less costs needing to be recovered through the PCA mechanism since that time. The $70.3 million of amortization offsets the collection from customers of prior years' deferrals.

***Other Operations and Maintenance Expenses*:** The changes in operations and maintenance (O&M) expenses for the periods presented are discussed below.

O&M - 2015 Compared with 2014: Other O&M expense decreased by $12.4 million in 2015 compared with 2014, a decrease of 3.5 percent, due to the following factors:

- $16.7 million was recorded as additional pension expense in 2014 related to a December 2011 Idaho regulatory settlement agreement, which required sharing with Idaho customers of a portion of earnings in excess of a 10 percent Idaho ROE (thereby reducing customers' future pension obligations). There were no additional expenses related to the settlement agreement in 2015;
- Excluding the additional 2014 pension expense, labor-related expenses increased $2.1 million, or 1.1 percent, in 2015 due to normal escalations in labor and benefits costs; and
- Other O&M expenses increased $2.2 million, the most notable increase being hydroelectric generation expenses that were $2.0 million higher, primarily due to increased repair costs and purchased services.

O&M - 2014 Compared with 2013: Other O&M expense increased by $5.7 million in 2014 compared with 2013, an increase of less than two percent, primarily due to an increase of $4.6 million in labor-related expenses caused by normal escalations in labor and benefits costs.

Gain on Sale of Investments

In 2013, Idaho Power recognized an $11.6 million gain on the sale of marketable securities. These investments relate to the Rabbi trust designated to provide funding for Idaho Power's obligations under its Security Plan for Senior Management Employees. Gross proceeds from the sale were $25.7 million. No such sale occurred in 2015 or 2014.

Income Taxes

IDACORP's and Idaho Power's 2015 income tax expense increased $28.9 million and $28.7 million, respectively, when compared to 2014. The increase was primarily due to greater Idaho Power pre-tax earnings in 2015 and lower flow-through income tax benefits from discrete items. In 2014, Idaho Power recorded a $24.5 million income tax benefit related to the cumulative impact of tax accounting method changes for its capitalized repairs deduction. During 2015, Idaho Power recorded an income tax benefit of $7.2 million for the tax deduction related to the call premium Idaho Power paid on the early redemption of long-term debt.

Income tax expense in 2014 decreased significantly compared with 2013, principally as a result of the Idaho Power capitalized repair deduction method changes. For additional information relating to IDACORP's and Idaho Power's income taxes, including the availability of tax credit carryforwards, see Note 2 - “Income Taxes” to the consolidated financial statements included in this report.

LIQUIDITY AND CAPITAL RESOURCES

Overview

Idaho Power has been pursuing significant enhancements to its utility infrastructure in an effort to ensure an adequate supply of electricity, to provide service to new customers, and to maintain system reliability. Idaho Power's existing hydroelectric and thermal generation facilities also require continuing upgrades and component replacement. Idaho Power's expenditures for property, plant and equipment, excluding AFUDC, were $284 million in 2015 and $265 million in 2014. Idaho Power expects these substantial capital expenditures to continue, with estimated total capital expenditures of nearly $1.5 billion over the period from 2016 through 2020.

Idaho Power funds its liquidity needs for capital expenditures through cash flows from operations, debt offerings, commercial paper markets, credit facilities, and capital contributions from IDACORP. During 2015, Idaho Power has continued its efforts to optimize operations, control costs, and generate operating cash inflows to meet operating expenditures, contribute to capital expenditure requirements, and pay dividends to shareholders. Idaho Power periodically files for rate adjustments for recovery of operating costs and both the return of, and a return on, capital investments to provide the opportunity to align Idaho Power's earned returns with those allowed by regulators. During 2016, Idaho Power intends to evaluate the timing of filing of its next general rate case.

As of February 12, 2016, IDACORP's and Idaho Power's access to debt, equity, and credit arrangements included:

- their respective $100 million and $300 million revolving credit facilities;
- IDACORP's shelf registration statement filed with the U.S. Securities and Exchange Commission (SEC) on May 22, 2013, which may be used for the issuance of debt securities and common stock, including up to 3 million shares of IDACORP common stock available for issuance under IDACORP's sales agency agreement executed in July 2013;
- Idaho Power's shelf registration statement, filed with the SEC jointly with IDACORP on May 22, 2013, which may be used for the issuance of first mortgage bonds and debt securities; $250 million is available for issuance under a selling agency agreement executed in July 2013 and pursuant to state regulatory authority; and
- IDACORP's and Idaho Power's issuance of commercial paper, which may be issued up to an amount equal to the available credit capacity under their respective credit facilities.

Based on planned capital expenditures and operating and maintenance expenses for 2016, the companies believe they will be able to meet capital requirements and fund corporate expenses during 2016 with a combination of existing cash and operating cash flows generated by Idaho Power's utility business. IDACORP and Idaho Power believe they could meet any short-term cash shortfall with existing credit facilities and expect to continue to manage short-term liquidity through commercial paper markets.

IDACORP and Idaho Power monitor capital markets with a view toward opportunistic debt and equity transactions, taking into account current and potential future long-term needs. As a result, IDACORP may issue debt securities or may issue common stock under the existing continuous equity program, and Idaho Power may issue debt securities, if the companies believe terms available in the capital markets are favorable and that issuances would be financially prudent. Idaho Power also periodically analyzes whether partial or full early redemption of one or more existing outstanding series of first mortgage bonds is desirable, and in some cases may refinance indebtedness with new indebtedness issued with more favorable terms, including interest rates lower than the series being redeemed. To that end, on March 6, 2015, Idaho Power issued $250 million in principal amount of 3.65% first mortgage bonds, Series J, maturing on March 1, 2045. On April 23, 2015, Idaho Power redeemed, prior to maturity, its $120 million in principal amount of 6.025% first mortgage bonds, medium-term notes due July 2018. In accordance with the redemption provisions of the original terms of the notes, the redemption included payment by Idaho Power of a make-whole premium of $17.9 million. Idaho Power used a portion of the net proceeds of the March 2015 sale of first mortgage bonds, medium-term notes to effect the redemption. During 2016, Idaho Power may determine to redeem prior to maturity one or more other outstanding series of first mortgage bonds, depending on capital availability and market conditions.

IDACORP and Idaho Power seek to maintain capital structures of approximately 50 percent debt and 50 percent equity, and maintaining this ratio influences IDACORP's and Idaho Power's debt and equity issuance decisions. As of December 31, 2015, IDACORP's and Idaho Power's capital structures, as calculated for purposes of applicable debt covenants, were as follows:

	IDACORP	Idaho Power
Debt	46%	48%
Equity	54%	52%

IDACORP and Idaho Power generally maintain their cash and cash equivalents in highly liquid investments, such as U.S. Treasury Bills, money market funds, and bank deposits.

Operating Cash Flows

IDACORP's and Idaho Power's principal sources of cash flows from operations are Idaho Power's sales of electricity and transmission capacity. Significant uses of cash flows from operations include the purchase of fuel and power, other operating expenses, interest, and pension plan contributions. Operating cash flows can be significantly influenced by factors such as weather conditions, rates and the outcome of regulatory proceedings, and economic conditions. As fuel and purchased power are significant uses of cash, Idaho Power has regulatory mechanisms in place that provide for the deferral and recovery of the majority of the fluctuation in those costs. However, if actual costs rise above the level allowed in retail rates, deferral balances increase (reflected as a regulatory asset), negatively affecting operating cash flows until such time as those costs, with interest, are recovered from customers.

IDACORP’s and Idaho Power’s operating cash inflows in 2015 were $353 million and $346 million, respectively, a decrease of $11 million for IDACORP and a slight increase for Idaho Power when compared with 2014. Significant items that affected the companies' operating cash flows in 2015 relative to 2014 were as follows:

- changes in regulatory assets and liabilities, mostly related to the relative amounts of power supply and fixed costs deferred and collected under the Idaho rate mechanisms, decreased operating cash inflows by $18 million;
- Idaho Power made $39 million of cash contributions to its defined benefit pension plan in 2015, compared with $30 million of cash contributions during 2014.
- changes in deferred taxes and in taxes accrued and receivable combined to increase cash flows by $34 million and $50 million at IDACORP and Idaho Power, respectively; and
- comparative changes in working capital balances due primarily to timing—principally related to a smaller decrease in accounts receivable in 2015 compared to the decrease in accounts receivable in 2014. Changes in accounts receivable balances reduced operating cash flows $16 million and $18 million for IDACORP and Idaho Power, respectively.

IDACORP's and Idaho Power's operating cash inflows in 2014 were $364 million and $343 million, respectively, increases of $59 million and $53 million, respectively, compared with 2013. Significant items that affected the companies' operating cash flows in 2014 relative to 2013 included:

- changes in regulatory assets and liabilities, mostly related to the relative amounts of power supply costs deferred and collected under the Idaho PCA mechanism, increased operating cash inflows by $58 million;
- changes in working capital balances due primarily to timing. Decreases in receivable balances from 2013 to 2014 compared with the increase in receivable balances experienced from 2012 to 2013 resulted in an increase to cash flows for 2014 of approximately $50 million for IDACORP and $52 million for Idaho Power;
- cash outflows related to income taxes increased by approximately $10 million for IDACORP and $16 million for Idaho Power from 2013 to 2014; and
- Idaho Power's joint venture, BCC, made net distributions to Idaho Power of $4 million in 2014, as compared with $15 million in 2013. A build-up in coal inventories at BCC during 2014 reduced BCC's cash available for distribution.

Investing Cash Flows

Investing activities consist primarily of capital expenditures related to new construction and improvements to Idaho Power's generation, transmission, and distribution facilities. Idaho Power's construction expenditures, including AFUDC, were $294 million, $274 million, and $247 million in 2015, 2014, and 2013, respectively. These capital expenditures were primarily for construction of utility infrastructure needed to address Idaho Power's aging plant and equipment, customer growth, and environmental and regulatory compliance requirements. As discussed in "Capital Requirements" below, Idaho Power received $11 million in both 2015 and 2013 from Boardman-to-Hemingway project joint permitting participants relating to a portion of these construction expenditures. Additionally, Idaho Power's investments in its Rabbi Trust designated to fund its non-qualified pension plan were $10 million, $8 million, and $7 million in 2015, 2014, and 2013, respectively. In 2015, Idaho Power used $30 million of Rabbi Trust assets to acquire company-owned life insurance.

Financing Cash Flows

Financing activities provide supplemental cash for both day-to-day operations and capital requirements as needed. Idaho Power funds liquidity needs for capital investment, working capital, managing commodity price risk, and other financial commitments through cash flows from operations, debt offerings, commercial paper markets, credit facilities, and capital contributions from IDACORP. IDACORP funds its cash requirements, such as payment of taxes, capital contributions to Idaho Power, and non-utility operating expenses through cash flows from operations, commercial paper markets, sales of common stock, and credit facilities. The following are significant items and transactions that affected financing cash flows in 2013, 2014, and 2015:

- on April 8, 2013, Idaho Power issued $75 million in principal amount of 2.50% first mortgage bonds due 2023 and $75 million in principal amount of 4.00% first mortgage bonds due 2043;
- on October 1, 2013 Idaho Power repaid at maturity $70 million of its 4.25% first mortgage bonds;
- on March 6, 2015, Idaho Power issued $250 million in principal amount of 3.65% first mortgage bonds, Series J, maturing on March 1, 2045;
- on April 23, 2015, Idaho Power redeemed, prior to maturity, its $120 million in principal amount of 6.025% first mortgage bonds, medium-term notes due July 2018;
- IDACORP and Idaho Power paid dividends of approximately $97 million, $88 million, and $79 million in 2015, 2014, and 2013, respectively; and
- IDACORP's net change in commercial paper borrowings were reductions of $11 million and $23 million and $15 million in 2015, 2014, and 2013 respectively .

Financing Programs and Available Liquidity

IDACORP Equity Programs: On July 12, 2013, IDACORP entered into a Sales Agency Agreement with BNY Mellon Capital Markets, LLC (BNYMCM), under which IDACORP may offer and sell up to 3 million shares of its common stock from time to time through BNYMCM as IDACORP's agent. IDACORP has no obligation to sell any minimum number of shares under the Sales Agency Agreement. As of the date of this report, 3 million shares of IDACORP common stock remain available for sale under the Sales Agency Agreement with BNYMCM. As of the date of this report, IDACORP does not expect to issue any shares of its common stock under the Sales Agency Agreement prior to its expiration in July 2016.

Effective July 1, 2012, IDACORP discontinued original issuances of common stock and instructed the plan administrators to use market purchases of IDACORP common stock for purposes of acquiring IDACORP common stock for the IDACORP, Inc. Dividend Reinvestment and Stock Purchase Plan and the Idaho Power Company Employee Savings Plan. However, IDACORP may determine at any time to resume original issuances of common stock under those plans. As noted above, an important component of that determination will be IDACORP's and Idaho Power's capital structure.

Idaho Power First Mortgage Bonds: Idaho Power's issuance of long-term indebtedness is subject to the approval of the IPUC, OPUC, and Wyoming Public Service Commission (WPSC). In April 2013, Idaho Power received orders from the IPUC, OPUC, and WPSC authorizing Idaho Power to issue and sell from time to time up to $500 million in aggregate principal amount of debt securities and first mortgage bonds, subject to conditions specified in the orders. Authority from the IPUC was through April 9, 2015. However, on April 1, 2015, the IPUC approved a two-year extension through April 9, 2017, continuing Idaho Power's authorization to issue and sell from time to time debt securities and first mortgage bonds. 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 seven percent.

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 in aggregate principal amount of first mortgage bonds, 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. As of the date of this report, $250 million remained on Idaho Power's Selling Agency Agreement for the issuance of first mortgage bonds, including Series J Notes, or debt securities.

The issuance of first mortgage bonds requires that Idaho Power meet interest coverage and security provisions set forth in the Indenture. Future issuances of first mortgage bonds are subject to satisfaction of covenants and security provisions set forth in the Indenture, market conditions, regulatory authorizations, and covenants contained in other financing agreements.

The Indenture limits the amount of first mortgage bonds at any one time outstanding to $2.0 billion, and as a result the maximum amount of first mortgage bonds Idaho Power could issue as of December 31, 2015 was limited to approximately $279 million. Idaho Power may increase the $2.0 billion limit on the maximum amount of first mortgage bonds outstanding by filing a supplemental indenture with the trustee as provided in the Indenture of Mortgage and Deed of Trust. Separately, the Indenture also limits the amount of additional first mortgage bonds that Idaho Power may issue to the sum of (a) the principal amount of retired first mortgage bonds and (b) 60 percent of total unfunded property additions, as defined in the Indenture. As of December 31, 2015, Idaho Power could issue approximately $1.5 billion of additional first mortgage bonds based on retired first mortgage bonds and total unfunded property additions.

Refer to Note 4 - “Long-Term Debt” to the consolidated financial statements included in this report for more information regarding long-term financing arrangements.

IDACORP and Idaho Power Credit Facilities: In November 2015, IDACORP and Idaho Power entered into Credit Agreements for $100 million and $300 million credit facilities, respectively. These facilities replaced IDACORP's and Idaho Power's existing Second Amended and Restated Credit Agreements, dated October 26, 2011, as amended. Each of the credit facilities may be used for general corporate purposes and commercial paper back-up. IDACORP's facility permits borrowings under a revolving line of credit of up to $100 million at any one time outstanding, including swingline loans not to exceed $10 million at any time and letters of credit not to exceed $50 million at any time. IDACORP's facility may be increased, subject to specified conditions, to $150 million. Idaho Power's facility permits borrowings through the issuance of loans and standby letters of credit of up to $300 million at any one time outstanding, including swingline loans not to exceed $30 million at any one time and letters of credit not to exceed $100 million at any time. Idaho Power's facility may be increased, subject to specified conditions, to $450 million. The interest rates for any borrowings under the facilities are based on either (1) a floating rate that is equal to the highest of the prime rate, federal funds rate plus 0.5 percent, or LIBOR rate plus 1.0 percent, or (2) the LIBOR rate, plus, in each case, an applicable margin, provided that the federal funds rate and LIBOR rate will not be less than zero percent. The applicable margin is based on IDACORP's or Idaho Power's, as applicable, senior unsecured long-term indebtedness credit rating, as set forth on a schedule to the credit agreements. The companies also pay a facility fee based on the respective company's credit rating for senior unsecured long-term debt securities. The credit facilities terminate on November 6, 2020, though IDACORP and Idaho Power may request up to two one-year extensions of the credit agreements, subject to certain conditions.

Each facility contains a covenant requiring each company to maintain a leverage ratio of consolidated indebtedness to consolidated total capitalization equal to or less than 65 percent as of the end of each fiscal quarter. In determining the leverage ratio, “consolidated indebtedness” broadly includes all indebtedness of the respective borrower and its subsidiaries, including, in some instances, indebtedness evidenced by certain hybrid securities (as defined in the credit agreement). “Consolidated total capitalization” is calculated as the sum of all consolidated indebtedness, consolidated stockholders' equity of the borrower and its subsidiaries, and the aggregate value of outstanding hybrid securities. At December 31, 2015, the leverage ratios for IDACORP and Idaho Power were 46 percent and 48 percent, respectively. IDACORP's and Idaho Power's ability to utilize the credit facilities is conditioned upon their continued compliance with the leverage ratio covenants included in the credit facilities. There are additional covenants, subject to exceptions, that prohibit certain mergers, acquisitions, and investments, restrict the creation of certain liens, and prohibit entering into any agreements restricting dividend payments from any material subsidiary. At December 31, 2015, IDACORP and Idaho Power believe they were in compliance with all facility covenants. Further, IDACORP and Idaho Power do not believe they will be in violation or breach of their respective debt covenants during 2016.

The events of default under both facilities include, without limitation, non-payment of principal, interest, or fees; materially false representations or warranties; breach of covenants; bankruptcy or insolvency events; condemnation of property; cross-default to certain other indebtedness; failure to pay certain judgments; change of control; failure of IDACORP to own free and clear of liens the voting stock of Idaho Power; the occurrence of specified events or the incurring of specified liabilities relating to benefit plans; and the incurring of certain environmental liabilities, subject, in certain instances, to cure periods.

Upon any event of default relating to the voluntary or involuntary bankruptcy of IDACORP or Idaho Power or the appointment of a receiver, the obligations of the lenders to make loans under the applicable facility and to issue letters of credit will automatically terminate and all unpaid obligations will become due and payable. Upon any other event of default, the lenders holding greater than 50 percent of the outstanding loans or greater than 50 percent of the aggregate commitments (required lenders) or the administrative agent with the consent of the required lenders may terminate or suspend the obligations of the lenders to make loans under the facility and to issue letters of credit under the facility and/or declare the obligations to be due and payable. During an event of default under the facilities, the lenders may, at their option, increase the applicable interest rates then in effect and the letter of credit fee by 2.0 percentage points per annum. A ratings downgrade would result in an increase in the cost of borrowing, but would not result in a default or acceleration of the debt under the facilities. However, if Idaho Power's ratings are downgraded below investment grade, Idaho Power must extend or renew its authority for borrowings under its IPUC and OPUC regulatory orders.

Without additional approval from the IPUC, the OPUC, and the WPSC, the aggregate amount of short-term borrowings by Idaho Power at any one time outstanding may not exceed $450 million. Idaho Power has obtained approval of the state public utility commissions of Idaho, Oregon, and Wyoming for the issuance of short-term borrowings through November 2022.

IDACORP and Idaho Power Commercial Paper: IDACORP and Idaho Power have commercial paper programs under which they issue unsecured commercial paper notes up to a maximum aggregate amount outstanding at any time not to exceed the available capacity under their respective credit facilities, described above. IDACORP's and Idaho Power's credit facilities are available to the companies to support borrowings under their commercial paper programs. The commercial paper issuances are used to provide an additional financing source for the companies' short-term liquidity needs. The maturities of the commercial paper issuances will vary, but may not exceed 270 days from the date of issue. Individual instruments carry a fixed rate during their respective terms, although the interest rates are reflective of current market conditions, subjecting the companies to fluctuations in interest rates.

Available Short-Term Borrowing Liquidity

The following table outlines available short-term borrowing liquidity as of the dates specified:

	December 31, 2015		December 31, 2014	
	IDACORP[(2)]	Idaho Power	IDACORP[(2)]	Idaho Power
Revolving credit facility	$ 100,000	$ 300,000	$ 125,000	$ 300,000
Commercial paper outstanding	(20,000)	—	(31,300)	—
Identified for other use[(1)]	—	(24,245)	—	(24,245)
Net balance available	$ 80,000	$ 275,755	$ 93,700	$ 275,755

[(1)] Port of Morrow and American Falls bonds that Idaho Power could be required to purchase prior to maturity under the optional or mandatory purchase provisions of the bonds, if the remarketing agent for the bonds were unable to sell the bonds to third parties.

[(2)] Holding company only.

At February 12, 2016, IDACORP had no loans outstanding under its credit facility and $17.5 million of commercial paper outstanding, and Idaho Power had no loans outstanding under its credit facility and no commercial paper outstanding. The table below presents additional information about short-term commercial paper borrowing during the years ended December 31, 2015 and 2014:

	December 31, 2015		December 31, 2014	
	IDACORP[(1)]	Idaho Power	IDACORP[(1)]	Idaho Power
Commercial paper:				
Year end:				
Amount outstanding	$ 20,000	$ —	$ 31,300	$ —
Weighted average interest rate	0.88%	—%	0.43%	—%
Daily average amount outstanding during the year	$ 22,054	$ —	$ 37,786	$ —
Weighted average interest rate during the year	0.53%	—%	0.32%	—%
Maximum month-end balance	$ 43,400	$ —	$ 47,300	$ —

[(1)] Holding company only.

Impact of Credit Ratings on Liquidity and Collateral Obligations

IDACORP's and Idaho Power's access to capital markets, including the commercial paper market, and their respective financing costs in those markets, depends in part on their respective credit ratings. The following table outlines the ratings of Idaho Power's and IDACORP's securities, and the ratings outlook, by Standard & Poor's Ratings Services and Moody's Investors Service as of the date of this report:

	IDACORP	Idaho Power
Moody's Investors Service:		
Rating Outlook	Stable	Stable
Long-Term Issuer Rating	Baa1	A3
First Mortgage Bonds	None	A1
Senior Secured Debt	None	A1
Commercial Paper	P-2	P-2
Tax-Exempt Debt	None	A3/VMIG-2
Standard & Poor's Rating Services:		
Corporate Credit Rating	BBB	BBB
Rating Outlook	Stable	Stable
Short-Term Rating	A-2	A-2

These security ratings reflect the views of the ratings agencies. An explanation of the significance of these ratings may be obtained from each rating agency. Such ratings are not a recommendation to buy, sell, or hold securities. Any rating can be revised upward or downward or withdrawn at any time by a rating agency if it decides that the circumstances warrant the change. Each rating agency has its own methodology for assigning ratings and, accordingly, each rating should be evaluated independently of any other rating.

Idaho Power maintains margin agreements relating to its wholesale commodity contracts that allow performance assurance collateral to be requested of and/or posted with certain counterparties. As of December 31, 2015, Idaho Power had posted $0.9 million of performance assurance collateral. Should Idaho Power experience a reduction in its credit rating on its unsecured debt to below investment grade Idaho Power could be subject to requests by its wholesale counterparties to post additional performance assurance collateral, and counterparties to derivative instruments and other forward contracts could request immediate payment or demand immediate ongoing full daily collateralization on derivative instruments and contracts in net liability positions. Based upon Idaho Power's current energy and fuel portfolio and market conditions as of December 31, 2015, the amount of additional collateral that could be requested upon a downgrade to below investment grade is approximately $11.6 million. To minimize capital requirements, Idaho Power actively monitors its portfolio exposure and the potential exposure to additional requests for performance assurance collateral through sensitivity analysis.

Capital Requirements

Idaho Power's construction expenditures, excluding AFUDC, were $284 million during the year ended December 31, 2015. The table below presents Idaho Power's estimated cash requirements for construction, excluding AFUDC, for 2016 through 2020 (in millions of dollars). However, given the uncertainty associated with the timing of infrastructure projects and associated expenditures, actual expenditures and their timing could deviate substantially from those set forth in the table.

	2016	2017	2018-2020
Ongoing capital expenditures (excluding item listed below in this table)	$ 280-285	$ 275-285	820-870
Jim Bridger plant selective catalytic reduction equipment (discussed below)	20-25	0	40-50
Total (excluding AFUDC)	$ 300-310	275-285	860-920

Major Infrastructure Projects: Idaho Power is engaged in the development of a number of significant projects and has entered into arrangements with third parties for joint development of infrastructure projects. The most notable projects are described below.

Jim Bridger Plant Selective Catalytic Reduction Equipment: Idaho Power and the plant co-owners are installing selective catalytic reduction (SCR) equipment to reduce nitrogen oxide (NO_x) emissions at the Jim Bridger power plant, in order to comply with regional haze rules. The regional haze rules provide for installation of SCR on unit 3 and unit 4. The rules provide for an equivalent technology for NO_x reductions on unit 2 by 2021 and unit 1 by 2022. Idaho Power estimates that the total cost for Idaho Power's share of the upgrades on units 3 and 4 is approximately $105 million, excluding AFUDC. As of December 31, 2015, Idaho Power had expended $83 million, excluding AFUDC, on SCR installation at units 3 and 4. The unit 3 SCR has been installed and was operating as of November 30, 2015. As of the date of this report, the unit 4 project remains on schedule and Idaho Power expects the total project cost to be at or below the originally estimated amount.

Boardman-to-Hemingway Transmission Line: The Boardman-to-Hemingway line, a proposed 300-mile, 500-kV transmission project between a station near Boardman, Oregon and the Hemingway station near Boise, Idaho, would provide transmission service to meet future resource needs. The Boardman-to-Hemingway line was included in the preferred resource portfolio in Idaho Power's 2015 IRP. In January 2012, Idaho Power entered into a joint funding agreement with PacifiCorp and the Bonneville Power Administration (BPA) to pursue permitting of the project. The joint funding agreement provides that Idaho Power's interest in the permitting phase of the project would be approximately 21 percent, and that during future negotiations relating to construction of the transmission line Idaho Power would seek to retain that percentage interest in the completed project. Assuming both other participants fund their full share of the total cost of the permitting phase of the project, Idaho Power's estimated share of the cost of the permitting phase of the project is approximately $40 million, including Idaho Power's AFUDC. Total cost estimates for the project are between $1.0 billion and $1.2 billion, including AFUDC for Idaho Power's share of the project. This cost estimate excludes the impacts of inflation and price changes of materials and labor resources that may occur following the date of the estimate. Idaho Power's share of the permitting phase of the project (excluding AFUDC) is included in the capital requirements table above. In December 2015, Idaho Power received an early payment of $11.4 million from a joint permitting participant. Construction costs beyond the permitting phase are not included in the table above.

Idaho Power has expended approximately $73 million on the Boardman-to-Hemingway project through December 31, 2015. Pursuant to the terms of the joint funding arrangements, approximately $35 million of that amount has been received by Idaho Power as reimbursement from the project participants as of December 31, 2015. Approximately $15 million more must be reimbursed to Idaho Power in the future by the project participants for expenses Idaho Power incurred, for a total amount reimbursable by joint permitting participants of $49 million. In addition to the $49 million amount, $5 million is subject to reimbursement at a later date from the joint permitting participants, assuming their continued participation in the project, for expenses Idaho Power incurred prior to execution of the joint funding arrangements. Idaho Power plans to seek recovery of its share of project costs through the regulatory process.

The permitting phase of the Boardman-to-Hemingway project is subject to review and approval by the U.S. Bureau of Land Management (BLM) as the lead federal agency on behalf of other federal agencies, the U.S. Forest Service, and the Oregon Department of Energy. The BLM issued a draft environmental impact statement (EIS) for the project in December 2014, and as of the date of this report Idaho Power expects the BLM to issue a final EIS during 2016 and a record of decision in late 2016 or early 2017. In the separate Oregon state permitting process, Idaho Power submitted a preliminary application for a site certificate in February 2013 and intends to finalize the amended preliminary application in 2016. Idaho Power is unable to determine an in-service date for the line but, given the status of ongoing permitting activities, expects the in-service date would be in 2022 or beyond.

Gateway West Transmission Line: Idaho Power and PacifiCorp are pursuing the joint development of the Gateway West project, a 500-kV transmission project between a station located near Douglas, Wyoming and the Hemingway station. In January 2012, Idaho Power and PacifiCorp entered a joint funding agreement for permitting of the project. Idaho Power's estimated cost for the permitting phase of the Gateway West project is approximately $64 million, including AFUDC. Idaho Power has expended approximately $29 million on the permitting phase of the project through December 31, 2015. As of the date of this report, Idaho Power estimates the total cost for its share of the project (including both permitting and construction) to be between $200 million and $400 million, including AFUDC. Idaho Power's share of the permitting phase of the project (excluding AFUDC) is included in the capital requirements table above. Construction costs beyond the permitting phase are not included in the table above.

The permitting phase of the project is subject to review and approval of the BLM. The BLM released its record of decision under the National Environmental Policy Act in November 2013. In its record of decision, the BLM identified its final decision on the routing of the project, issued right-of-way grants on public land for some segments, and deferred a decision on two segments (in both of which Idaho Power has an interest) to resolve routing concerns in those areas. Several interested parties have appealed the BLM's record of decision, and Idaho Power has intervened in the proceedings. The BLM has initiated the supplemental EIS process for the two deferred segments. As of the date of this report, the BLM's schedule provides for the issuance of a record of decision on the two deferred segments in 2016.

Hells Canyon Complex Relicensing: The HCC, located on the Snake River where it forms the border between Idaho and Oregon, provides approximately 68 percent of Idaho Power's hydroelectric generating nameplate capacity and 32 percent of its total generating nameplate capacity. Idaho Power has been engaged in the process of obtaining from the FERC a new long-term license for the HCC. As noted in "Regulatory Matters" in this MD&A, the past and anticipated future costs associated with obtaining a new long-term license for the HCC are significant. Idaho Power expects that the annual capital expenditures and operating and maintenance expenses associated with compliance with the terms and conditions of the long-term license could also be substantial, but the company is currently unable to estimate those costs in light of the uncertainty surrounding the ultimate terms and conditions that may be included in the license. Idaho Power intends to seek recovery of those relicensing and compliance costs in rates through the regulatory process.

Shoshone Falls Plant Expansion: The Shoshone Falls plant expansion project was included in Idaho Power's 2013 IRP and, as originally planned, was to consist of constructing a new powerhouse, intake structure, penstock, and substation and installing a new turbine to increase the nameplate generation capacity of the plant from 12.5 MW to 61.5 MW. However, following additional analysis of the costs and potential benefits of the expansion, Idaho Power's 2015 IRP includes in the near-term action plan a modified project that would result in a significantly smaller increase in nameplate generation capacity at the facility, in a range of 1.7 MW to 4 MW, with a potential on-line date as early as 2019. Idaho Power is performing additional engineering and cost studies to determine the most suitable project that will optimize and improve the reliability of the facility. Following consultation with FERC staff, Idaho Power has concluded it can proceed with the modified expansion under the terms and conditions of the current operating license.

Completed Transmission System Transaction: To enhance the abilities of Idaho Power and PacifiCorp to serve their respective customers, in October 2014, Idaho Power and PacifiCorp executed a Joint Ownership and Operating Agreement (Joint Operating Agreement) applicable to certain transmission-related equipment to be exchanged by Idaho Power and PacifiCorp. The asset exchange was finalized on October 30, 2015, under the terms of a Joint Purchase and Sale Agreement dated October 24, 2014, between Idaho Power and PacifiCorp. Under the terms of the Joint Purchase and Sale Agreement each party agreed to transfer to the other transmission-related equipment with an estimated year-end 2014 net book value of approximately $43 million, subject to true-up as of the closing date. Additionally, the Joint Purchase and Sale Agreement terminated or amended a number of legacy long-term agreements related to the ownership and operation of transmission-related equipment and transmission services between Idaho Power and PacifiCorp. In 2014, Idaho Power collected approximately $8 million in transmission revenues under legacy long-term transmission agreements that were terminated in connection with the Joint Purchase and Sale Agreement. As a result of the transaction and termination of those long-term transmission agreements, an increase to Idaho Power's OATT rate will be phased-in over a two-year period, as discussed in "Regulatory Matters" in the MD&A.

Other Infrastructure Projects: Idaho Power continues to add to its system to accommodate for growth and to reinvest for reliability and general system improvement. These system enhancement projects involve significant capital expenditures. Examples of system enhancements over the period 2016 through 2020, and their estimated costs, include the following:

- $50-$85 million per year for transmission-related projects other than the Boardman-to-Hemingway and Gateway West projects;
- $30-$35 million per year for reconstruction of distribution lines;
- $15-$20 million per year for replacement of underground distribution cables;
- $25-$40 million per year for ongoing thermal plant improvement programs other than SCR equipment;
- $25-$40 million per year for hydroelectric plant improvement programs;
- $5-$10 million per year for reliability-related construction projects, such as wood pole crossarm replacements and feeder system improvement; and
- $30-$45 million per year for general plant improvements, such as information technology, facilities, and fleet vehicles.

Approval of Long-Term Service Agreement for Natural Gas Plants: During 2015, Idaho Power executed a long-term service agreement for maintenance services at three of Idaho Power's natural gas plants, with a total estimated obligation of $82 million over the term of the agreement. In addition to the provision of maintenance services to Idaho Power, the agreement provided for Idaho Power's sale of approximately $22 million of capitalized spare parts to the service provider. Idaho Power expects that the arrangement will decrease the long-term costs of operating Idaho Power's natural gas plants. The agreement became effective in the fourth quarter of 2015, following receipt of an order on reconsideration from the IPUC approving accounting treatment acceptable to Idaho Power.

Environmental Regulation Costs: Idaho Power anticipates that it will incur significant expenditures for the installation of environmental controls at its coal-fired plants and for its hydroelectric relicensing efforts. The near-term cost estimates for environmental matters are summarized in Part I, Item 1 - "Business" of this report. The capital portion of these amounts is included in the Capital Requirements table above but does not include costs related to possible changes in current or new environmental laws or regulations and enforcement policies that may be enacted in response to issues such as climate change and emissions from coal-fired and gas-fired generation plants.

Long-Term Resource Planning: The IPUC and OPUC require that Idaho Power prepare biennially an Integrated Resource Plan (IRP). Idaho Power filed its most recent IRP in June 2015. The IRP seeks to forecast Idaho Power's loads and resources for a 20-year period, analyzes potential supply-side and demand-side resource options, and identifies potential near-term and long-term actions. The 2015 IRP includes as near-term action items the continued permitting and planning for the Boardman-to-Hemingway transmission line and further investigation of the early retirement of the North Valmy power plant in collaboration with the plant's co-owner. The near-term action plan also includes a decrease in the size of the planned Shoshone Falls expansion described above, as well as commencement of an economic evaluation of environmental control retrofits for units 1 and 2 at the Jim Bridger power plant. Additional information on Idaho Power's IRP is included in Part I, Item 1 - "Business - Resource Planning" in this report.

Defined Benefit Pension Plan Contributions and Recovery

Idaho Power contributed $39 million, $30 million, and $30 million to its defined benefit pension plan in 2015, 2014, and 2013, respectively. Idaho Power estimates that it has no minimum contribution requirement for 2016, though it plans to contribute at least $20 million to the pension plan during 2016. Idaho Power may elect to contribute more than that amount based on long-term projections. Idaho Power's contributions are made in a continued effort to balance the regulatory collection of these expenditures with the amount and timing of contributions to mitigate the cost of being in an underfunded position. In 2016 and beyond, Idaho Power expects continuing significant contribution obligations under the pension plan. Refer to Note 11 - "Benefit Plans" to the consolidated financial statements included in this report and the section titled "Contractual Obligations" below in this MD&A for information relating to those obligations.

Idaho Power defers its Idaho-jurisdiction pension expense as a regulatory asset until recovered from Idaho customers. As of December 31, 2015, Idaho Power's deferral balance associated with the Idaho jurisdiction was $82.5 million. Deferred pension costs are expected to be amortized to expense to match the revenues received when contributions are recovered through rates. Idaho Power only records a carrying charge on the unrecovered balance of cash contributions. The IPUC has authorized Idaho Power to recover and amortize $17.1 million of deferred pension costs annually, and has applied $68.1 million against the deferred amount under its Idaho sharing mechanisms. The primary impact of pension contributions is on timing of cash flows, as cost recovery lags behind the timing of contributions.

Contractual Obligations

The following table presents IDACORP's and Idaho Power's contractual cash obligations as of December 31, 2015, for the respective periods in which they are due:

	Payments Due by Period				
	Total	**2016**	**2017-2018**	**2019-2020**	**Thereafter**
	(millions of dollars)				
Long-term debt[1]	$ 1,747	$ 1	$ 1	$ 330	$ 1,415
Future interest payments[2]	1,417	83	165	153	1,016
Operating leases[3]	17	—	2	2	13
Purchase obligations:					
Cogeneration and small power production[4]	4,736	199	475	469	3,593
Fuel supply agreements	251	60	59	18	114
Other[5]	263	62	52	36	113
Pension and postretirement benefit plans[6]	264	8	75	138	43
Other long-term liabilities	1	—	1	—	—
Total	$ 8,696	$ 413	$ 830	$ 1,146	$ 6,307

(1) For additional information, see Note 4 – "Long-Term Debt" to the consolidated financial statements included in this report.

(2) Future interest payments are calculated based on the assumption that all debt is outstanding until maturity. For debt instruments with variable rates, interest is calculated for all future periods using the rates in effect at December 31, 2015.

(3) The operating leases include right-of-way easements. Approximately $1 million of the obligations included have contracts that do not specify terms related to expiration. As these contracts are presumed to continue indefinitely, 10 years of information, estimated based on current contract terms, has been included in the table for presentation purposes.

(4) Subsequent to the end of 2015, as of February 5, 2016, three power purchase contracts with solar projects not yet online with a combined nameplate capacity of 25 MW had terminated. Termination of the agreements reduced Idaho Power's contractual payment obligations by approximately $74 million over the 20-year lives of the terminated contracts.

(5) Approximately $84 million of the amounts in other purchase obligations are contracts that do not specify terms related to expiration. As these contracts are presumed to continue indefinitely, 10 years of information, estimated based on current contract terms, has been included in the table for presentation purposes. Other purchase obligations also includes Idaho Power's estimated proportionate funding obligation for goods and services under non-fuel purchase agreements at its jointly owned generation facilities. In some instances, Idaho Power is not a direct party to an underlying purchase agreement, but is obligated under the instruments governing the joint ventures to reimburse the co-owner for payments the co-owner makes pursuant to the purchase agreement. Those estimated amounts have been included in the table above.

(6) Idaho Power estimates pension contributions based on actuarial data. As of the date of this report, Idaho Power cannot estimate pension contributions beyond 2020 with any level of precision, and amounts through 2020 are estimates only and are subject to change. For more information on pension and postretirement plans, refer to Note 11 – "Benefit Plans" to the consolidated financial statements included in this report.

Dividends

The amount and timing of dividends paid on IDACORP's common stock are within the discretion of IDACORP's board of directors. IDACORP's board of directors reviews the dividend rate periodically to determine its appropriateness in light of IDACORP's current and long-term financial position and results of operations, capital requirements, rating agency considerations, contractual and regulatory restrictions, legislative and regulatory developments affecting the electric utility industry in general and Idaho Power in particular, competitive conditions, and any other factors the board of directors deems relevant. The ability of IDACORP to pay dividends on its common stock is dependent upon dividends paid to it by its subsidiaries, primarily Idaho Power.

IDACORP has a dividend policy that provides for a target long-term dividend payout ratio of between 50 and 60 percent of sustainable IDACORP earnings, with the flexibility to achieve that payout ratio over time and to adjust the payout ratio or to deviate from the target payout ratio from time to time based on the various factors that drive IDACORP's board of directors' dividend decisions. Notwithstanding the dividend policy adopted by IDACORP's board of directors, the dividends IDACORP pays remain in the discretion of the board of directors who, when evaluating the dividend amount, will continue to take into account the factors above, among others. In September of 2013, 2014, and 2015, IDACORP's board of directors voted to increase the quarterly dividend to $0.43 per share, $0.47 per share, and $0.51 per share of IDACORP common stock, respectively. IDACORP's 2015 calendar year payout ratio was 50 percent.

For additional information relating to IDACORP and Idaho Power dividends, including restrictions on IDACORP's and Idaho Power's payment of dividends, see Note 6 – "Common Stock" to the consolidated financial statements included in this report.

Contingencies and Proceedings

IDACORP and Idaho Power are involved in a number of litigation, alternative dispute resolution, and administrative proceedings, and are subject to claims and legal actions arising in the ordinary course of business, that could affect their future results of operations and financial condition. Certain legal or administrative proceedings to which IDACORP or Idaho Power are parties or are otherwise involved, and certain actual or potential legal claims pertaining to Idaho Power, are described in Note 10 - "Contingencies" to the consolidated financial statements included in this report. Except where noted in Note 10, in many instances IDACORP and Idaho Power are unable to predict the outcomes of the matters or estimate the impact the proceedings may have on their financial positions, results of operations, or cash flows.

Idaho Power is also actively monitoring various environmental regulations 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 determine the financial impact of potential new 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.

Off-Balance Sheet Arrangements

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 $73 million at December 31, 2015, representing IERCo's one-third share of BCC's total reclamation obligation of $218 million. BCC has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. At December 31, 2015, the value of the reclamation trust fund totaled $70 million. During 2015, the reclamation trust fund distributed approximately $6 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. Starting in 2010, BCC began applying a nominal surcharge to coal sales in order to maintain adequate reserves in the reclamation trust fund. Because of the existence of the fund and the ability to apply a per-ton surcharge, the estimated fair value of this guarantee is minimal.

REGULATORY MATTERS

Introduction

Idaho Power's development of rate case plans takes into consideration short-term and long-term needs for rate relief and involves several factors that can affect the timing of rate filings. These factors include, among others, in-service dates of major capital investments, the timing of changes in major revenue and expense items, and customer growth rates. Idaho Power's most recent general rate cases in Idaho and Oregon were filed during 2011, and Idaho Power filed a large single-issue rate case for the Langley Gulch power plant in Idaho and Oregon in 2012. These significant rate cases resulted in the resetting of base rates in both Idaho and Oregon during 2012. Idaho Power also reset its base-rate power supply expenses in the Idaho jurisdiction for purposes of updating the collection of costs through retail rates in 2014, but without a resulting net increase in rates. Between general rate cases, Idaho Power relies upon power cost adjustment mechanisms, tariff riders, and other mechanisms to reduce regulatory lag, which refers to the period of time between making an investment or incurring an expense and recovering that investment or expense and earning a return.

Management's regulatory focus in recent years has been largely on regulatory settlement stipulations and the design of rate mechanisms. During 2016, Idaho Power plans to continue to assess its need to file and timing of a general rate case in its two retail jurisdictions, based on its consideration of the factors described above, among others.

Notable Retail Rate Changes in Idaho and Oregon

Included in the table that follows are notable regulatory developments during 2013, 2014, and 2015 that affected Idaho Power's results for the periods. Also refer to Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report for a description of regulatory mechanism and associated orders of the IPUC and OPUC, which should be read in conjunction with the discussion of regulatory matters in this MD&A.

Description	Effective Date	Estimated Annualized Revenue Impact (millions)[(1)]
2013 Idaho FCA[(2)]	6/1/2013	(1)
2013 Idaho PCA[(2)(3)]	6/1/2013	140
2013 Oregon APCU[(2)]	6/1/2013	3
2014 Idaho FCA[(2)]	6/1/2014	6
2014 Idaho PCA[(2)(4)]	6/1/2014	(88)
Transfer of power supply costs from the Idaho PCA mechanism to Idaho base rates[(5)]	6/1/2014	99
2015 Idaho FCA[(2)]	6/1/2015	2
2015 Idaho PCA[(2)(6)]	6/1/2015	(12)

(1) The annual amount collected in rates is typically not recovered on a linear basis (i.e., 1/12th per month), and is instead recovered in proportion to general business sales volumes.

(2) The rate changes for the Idaho PCA and FCA are applicable only for one-year periods. Similarly, a portion of the rate changes from the Oregon APCU are applicable only for one-year periods.

(3) 2013 PCA rates reflect $7 million of Idaho revenue-sharing related to 2012 financial results pursuant to an IPUC order issued in 2013 under regulatory settlement agreements approved in January 2010 and December 2011. The $140 million increase in PCA rates includes the reduction in the PCA mechanism component of the revenue sharing amount from $27 million for the 2012 PCA to $7 million for the 2013 PCA.

(4) 2014 PCA rates reflect (a) the application of $20 million of surplus Idaho energy efficiency rider funds, (b) $8 million of customer revenue sharing for the year 2013 under a regulatory settlement agreement approved in December 2011, and (c) a $99 million shift in base net power supply expenses from recovery via the PCA mechanism to recovery through base rates.

(5) See footnote (4) above. Approval of the transfer of collection of specified power supply costs from the Idaho PCA mechanism to Idaho base rates resulted in no net change in customer rates.

(6) 2015 PCA rates reflect the application of (a) a customer rate credit of $8.0 million for sharing of revenues with customers for the year 2014 under the terms of a December 2011 settlement stipulation, (b) a $1.5 million customer benefit relating to a change to the PCA methodology described below, and (c) $4.0 million of surplus Idaho energy efficiency rider funds.

Idaho and Oregon General Rate Cases and Base Rate Adjustments

Effective January 1, 2012, Idaho Power implemented new Idaho base rates resulting from the regulatory settlement of a general rate case filing Idaho Power made in 2011. In the general rate case, the IPUC issued an order approving a settlement stipulation that provided for an overall 7.86 percent authorized rate of return on an Idaho-jurisdiction rate base of approximately $2.36 billion. The settlement stipulation resulted in a $34.0 million overall increase in Idaho Power's annual Idaho-jurisdictional base rate revenues. Neither the IPUC's order nor the settlement stipulation specified an authorized rate of return on equity.

Effective March 1, 2012, Idaho Power implemented new Oregon base rates resulting from its receipt of an order from the OPUC approving a settlement stipulation in its general rate case proceedings that provided for a $1.8 million base rate revenue increase, a rate of return on equity of 9.9 percent, and an overall rate of return of 7.757 percent in the Oregon jurisdiction.

Idaho and Oregon base rates were subsequently adjusted again in 2012, in connection with Idaho Power's completion of the Langley Gulch power plant. In June 2012, the IPUC issued an order approving a $58.1 million increase in annual Idaho-jurisdiction base rate revenues, effective July 1, 2012, for inclusion of the investment and associated costs of the plant in rates. The order also provided for a $335.9 million increase in Idaho rate base. On September 20, 2012, the OPUC issued an order approving a $3.0 million increase in annual Oregon jurisdiction base rate revenues, effective October 1, 2012, for inclusion of the investment and associated costs of the plant in Oregon rates.

In March 2014, the IPUC issued an order approving Idaho Power's application 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 became effective June 1, 2014. Approval of the order removed the Idaho-jurisdictional portion of those expenses (approximately $99 million) from collection via the Idaho PCA mechanism and instead results in collecting that portion through base rates.

Non-Base Rate Idaho Regulatory Settlement Stipulations

Settlement Stipulation for 2012 to 2014: In December 2011, the IPUC issued an order, separate from the then-pending Idaho general rate case proceeding, approving a settlement stipulation that allowed Idaho Power to, in certain circumstances, amortize additional ADITC if Idaho Power's actual Idaho ROE for 2012, 2013, or 2014 was less than 9.5 percent, to help achieve a 9.5 percent Idaho ROE for the applicable year. The more specific terms and conditions of the December 2011 Idaho settlement stipulation are described in Note 3 - "Regulatory Matters - *Notable Idaho Regulatory Matters*" to the consolidated financial statements included in this report. Under the December 2011 settlement stipulation, when Idaho Power's actual Idaho ROE for any of those years exceeded 10.0 percent, Idaho Power was required to share a portion of its Idaho-jurisdiction earnings with Idaho customers. As Idaho Power's 2012, 2013, and 2014 Idaho ROE exceeded 10.0 percent, Idaho Power did not amortize additional ADITC for those years, but instead shared earnings with customers. The amounts Idaho Power recorded for sharing for those years were as follows (in millions of dollars):

	2014	2013	2012
Additional pension expense funded through sharing	$ 16.7	$ 16.5	$ 14.6
Provision against current revenue as a result of sharing	8.0	7.6	7.2
Total	$ 24.7	$ 24.1	$ 21.8

Settlement Stipulation for 2015 to 2019: In October 2014, the IPUC issued an order approving an extension, with modifications, of the terms of the December 2011 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 more specific terms and conditions of the October 2014 settlement stipulation are described in Note 3 - "Regulatory Matters - *Notable Idaho Regulatory Matters*" to the consolidated financial statements included in this report. IDACORP and Idaho Power believe that the terms allowing amortization of additional ADITC in the October 2014 settlement stipulation provide the companies with a greater degree of earnings stability than would be possible without the terms of the stipulation in effect.

Idaho Power recorded no additional ADITC amortization and a $3.2 million provision against current revenue for sharing with customers for 2015, as its Idaho ROE for 2015 was above 10.0 percent. Accordingly, the full $45 million of additional ADITC remains available for future use under the terms of the settlement stipulation.

Modifications to Idaho Annual Rate Adjustment Mechanisms

PCA Mechanism: In July 2014, the IPUC opened a docket pursuant to which Idaho Power, the IPUC Staff, and other interested parties evaluated Idaho Power's application of the true-up component of the PCA mechanism. The July 2014 docket arose from a prior order of the IPUC, which noted that the IPUC Staff believed that Idaho Power's application of the true-up component introduced a line-loss bias that inflated the true-up revenue that Idaho Power collects under the PCA. In May 2015, the IPUC approved a settlement stipulation that modified the calculation of the true-up component of the PCA mechanism. The mechanics of the PCA mechanism and the terms of the PCA settlement stipulation are described in Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report.

FCA Mechanism:Also in July 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. Concerns cited included the application of weather-normalization, the customer count methodology, the rate adjustment cap, cross-subsidization issues, and whether the FCA is in fact effectively removing Idaho Power's disincentive to aggressively pursue energy efficiency programs.

The FCA 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. Stated generally, under the FCA Idaho Power charges residential and small commercial customers when it recovers less "actual fixed costs per customer" than the base level of fixed costs that the IPUC authorized for recovery through rates in the last general rate case, and Idaho Power credits those customers when its "actual fixed costs per customer" recovered exceed that base level of fixed costs. The FCA is adjusted each year to collect, or refund, the difference between the authorized fixed-cost recovery amount and the actual fixed costs recovered by Idaho Power during the year.

In May 2015, the IPUC approved a settlement stipulation that modified the FCA mechanism by replacing weather-normalized sales with actual sales in the calculation of the FCA, applicable for the entirety of calendar year 2015 and thereafter, with new rates effective June 1, 2016. The settlement stipulation also provided that a modified rate design should be considered at a later time for residential and small commercial customers to address the financial disincentive caused by the existing rate design that the FCA is intended to remove. The rate design may include, but would not be limited to, reduced energy charges, increased monthly service charges, and the introduction of demand charges.

In years when actual sales per customer are higher than weather-normalized sales due to high summer or low winter temperatures, Idaho Power expects that the new FCA methodology will be less favorable to Idaho Power than the prior methodology. Conversely, Idaho Power expects that the new FCA methodology will be more favorable to Idaho Power in years when actual sales per customer are lower than weather normalized sales due to cooler summer or warmer winter temperatures. Implementation of the new methodology was retroactive to January 1, 2015, as contemplated by the settlement stipulation. For 2015, application of the new FCA methodology resulted in Idaho Power recording greater FCA revenues than would have been recorded for the year under the prior mechanism.

Deferred Net Power Supply Costs

Deferred power supply costs represent certain differences between Idaho Power's actual net power supply costs and the costs included in its retail rates, the latter being based on annual forecasts of power supply costs. Deferred power supply costs are recorded on the balance sheets for future recovery or refund through customer rates. Idaho Power's PCA mechanisms in its Idaho and Oregon jurisdictions provide for annual adjustments to the rates charged to retail customers. The PCA mechanism and associated financial impacts are described in "Results of Operations" in this MD&A and in Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report.

Factors that have influenced significant PCA rate changes in recent years include year-to-year volatility in hydroelectric generation conditions, market energy prices and the volume of off-system sales, power purchase costs from renewable energy projects, and revenue sharing under Idaho regulatory settlement stipulations. From year to year, the factors that influence power supply costs can vary significantly, which can result in significant accruals and deferrals under the PCA mechanism. The PCA rate changes reflected in the table under the heading "Notable Retail Rate Changes in Idaho and Oregon" are illustrative of the volatility of net power supply costs and the impact on PCA rates.

As noted above under the heading "Idaho and Oregon General Rate Cases and Base Rate Adjustments," in light of the existence of permanent increases in power supply costs, in March 2014 the IPUC issued an order approving Idaho Power's application requesting recovery of a portion of its ongoing power supply costs through base rates rather than through the Idaho PCA mechanism.

The following table summarizes the change in deferred net power supply costs over the prior two years.

	Idaho	Oregon[1]	Total
Balance at December 31, 2013	$ 84,843	$ 6,611	$ 91,454
Current period net power supply costs deferred	48,104	—	48,104
Revenue sharing applied to deferred power supply costs	(7,624)	—	(7,624)
Energy efficiency rider funds applied to deferred power supply costs	(20,000)	—	(20,000)
Prior deferred costs amortized and recovered through rates	(48,489)	(2,210)	(50,699)
SO_2 allowance and renewable energy certificate (REC) sales	(2,895)	(127)	(3,022)
Interest and other	573	403	976
Balance at December 31, 2014	54,512	4,677	59,189
Current period net power supply costs deferred	35,802	—	35,802
Revenue sharing applied to deferred power supply costs	(7,999)	—	(7,999)
Energy efficiency rider funds applied to deferred power supply costs	(4,000)	—	(4,000)
Prior deferred costs amortized and recovered through rates	(32,519)	(2,294)	(34,813)
SO_2 allowance and renewable energy certificate (REC) sales	(1,575)	(70)	(1,645)
Interest and other	335	351	686
Balance at December 31, 2015	$ 44,556	$ 2,664	$ 47,220

[1] Oregon power supply cost deferrals are subject to a statute that specifically limits rate amortizations of deferred costs to six percent of gross Oregon revenue per year (approximately $3 million). Deferrals are amortized sequentially.

Open Access Transmission Tariff Rate Proceedings

Idaho Power uses a formula rate for transmission service provided under its OATT. The transmission rates are updated annually based primarily on financial and operational data Idaho Power files with the FERC. In August 2015, Idaho Power filed with the FERC and publicly posted its final informational filing for its 2015 transmission rate, reflecting a transmission rate of $23.43 per kW-year, to be effective for the period from October 1, 2015 to September 30, 2016. Historic OATT rate information is included in Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report.

Leading up to the final informational filing, in a draft transmission rate posting Idaho Power made in June 2015, Idaho Power included in its draft OATT rate calculations the expected changes in demand associated with the then-pending transmission system transaction with PacifiCorp (described in "Liquidity and Capital Resources" in this MD&A), resulting in a draft rate of $33.23 per kW-year. The transmission system transaction terminated certain legacy transmission agreements and provided for new long-term point-to-point transmission service for PacifiCorp. In response to concerns from transmission customers, Idaho Power subsequently shifted its procedural approach for incorporating the impacts of the transmission system transaction on its OATT rate. Idaho Power's 2015 transmission rate of $23.43 per kW-year for the period from October 1, 2015 to September 30, 2016 does not include the impact of the transmission system transaction. In a July 2015 filing, Idaho Power requested clarification from the FERC as to when Idaho Power may fully incorporate the effects of the pending transmission system transaction in the formula used to determine its OATT rate. On November 19, 2015, the FERC issued an order requiring Idaho Power to reflect historic loads in the load denominator used in the transmission formula rate, resulting in an OATT rate increase that is phased-in over a two-year period rather than on an accelerated basis.

Relicensing of Hydroelectric Projects

Overview: Idaho Power, like other utilities that operate nonfederal hydroelectric projects on qualified waterways, obtains licenses for its hydroelectric projects from the FERC. These licenses have a term of 30 to 50 years depending on the size, complexity, and cost of the project. The expiration dates for the FERC licenses for each of the facilities are included in Part I - Item 2 - "Properties" in this report. Costs for the relicensing of Idaho Power's hydroelectric projects are recorded in construction work in progress until new multi-year licenses are issued by the FERC, at which time the charges are transferred to electric plant in service. Relicensing costs and costs related to new licenses will be submitted to regulators for recovery through the ratemaking process. Relicensing costs of $221 million for the HCC, Idaho Power's largest hydroelectric complex and a major relicensing effort, were included in construction work in progress at December 31, 2015. As of the date of this report, the IPUC authorizes Idaho Power to include in its Idaho jurisdiction rates approximately $6.5 million annually ($10.7 million when grossed-up for the effect of income taxes) of AFUDC relating to the HCC relicensing project. Collecting these amounts now will reduce the amount collected in the future once the HCC relicensing costs are approved for recovery in base rates. As of December 31, 2015, Idaho Power's regulatory liability for collection of AFUDC relating to the HCC was $88 million. In addition to the discussion below, see "Environmental Matters" in this MD&A for a discussion of environmental compliance under FERC licenses for Idaho Power's hydroelectric generating plants.

Hells Canyon Complex: The HCC, located on the Snake River where it forms the border between Idaho and Oregon, provides approximately 68 percent of Idaho Power's hydroelectric generating nameplate capacity and 32 percent of its total generating nameplate capacity. In July 2003, Idaho Power filed an application with the FERC for a new license in anticipation of the July 2005 expiration of the then-existing license. Since the expiration of that license, Idaho Power has been operating the project under annual licenses issued by the FERC. In December 2004, Idaho Power and eleven other parties, including National Marine Fisheries Service (NMFS) and U.S. Fish and Wildlife Service (USFWS), involved in the HCC relicensing process entered into an interim agreement that addresses the effects of the ongoing operations of the HCC on Endangered Species Act (ESA) listed species pending the relicensing of the project. In August 2007, the FERC Staff issued a final EIS for the HCC, which the FERC will use to determine whether, and under what conditions, to issue a new license for the project. The purpose of the final EIS is to inform the FERC, federal and state agencies, Native American tribes, and the public about the environmental effects of Idaho Power's operation of the HCC. Certain portions of the final EIS involve issues that may be influenced by water quality certifications for the project under Section 401 of the Clean Water Act (CWA) and formal consultations under the ESA, which remain unresolved.

In connection with its relicensing efforts, Idaho Power has filed water quality certification applications, required under Section 401 of the CWA, with the states of Idaho and Oregon requesting that each state certify that any discharges from the project comply with applicable state water quality standards. Section 401 of the CWA requires that a state either approve or deny a Section 401 water quality certification application within one year of the filing of the application or the state may be considered to have waived its certification authority under the CWA. As a consequence, Idaho Power has been filing and withdrawing its

Section 401 certification applications with Oregon and Idaho on an annual basis while it has been working with the states to identify measures that will provide reasonable assurance that discharges from the HCC will adequately address applicable water quality standards.

In September 2007, in connection with the issuance of its final EIS, the FERC notified the NMFS and the USFWS of its determination that the licensing of the HCC was likely to adversely affect ESA-listed species, including the bull trout and fall Chinook salmon and steelhead, under the NMFS's and USFWS's jurisdiction and requested that the NMFS and USFWS initiate formal consultation under Section 7 of the ESA on the licensing of the HCC. Each of the NMFS and USFWS responded to the FERC that the conditions relating to the licensing of the HCC were not fully described or developed in the final EIS as the measures to address the water quality effects of the project were yet to be fully defined by the Section 401 certification process pending before the Oregon and Idaho Departments of Environmental Quality. The NMFS and USFWS therefore recommended that formal consultation under the ESA be delayed until the Section 401 certification process is completed.

Idaho Power continues to work with Idaho and Oregon in the development of measures to provide reasonable assurance that any discharges from the HCC will comply with applicable state water quality standards so that appropriate water quality certifications can be issued for the project, and continues to cooperate with the USFWS, NMFS, and the FERC in an effort to address ESA concerns. Idaho Power has begun the process for construction of new aerated runners at the Brownlee project (part of the HCC) at an estimated cost of $50 million. Other measures that have been proposed or considered have included modification of spillways at Brownlee and Hells Canyon to address total dissolved gas issues, and upstream watershed improvements or the installation of a temperature control structure to address water temperatures during a small portion of the year. If Idaho Power is required to take these or other additional measures to satisfy relicensing requirements, it could add substantially to project costs. Idaho Power continues to work with the Oregon and Idaho Departments of Environmental Quality on the water quality certification issue and the water quality measures that will be required to obtain 401 certification.

As of the date of this report, Idaho Power is unable to predict the timing of issuance by the FERC of any license order or the ultimate capital investment and ongoing operating and maintenance costs Idaho Power will incur in complying with any new license. However, as of the date of this report, Idaho Power estimates that the annual costs it will incur to obtain a new long-term license for the HCC, including AFUDC but excluding costs expected to be incurred for complying with the license after issuance, are likely to range from $20 million to $30 million until issuance of the license.

Renewable Energy Standards and Contracts

Renewable Portfolio Standards: Numerous proponents have introduced legislation in the U.S. Congress that would require electric utilities to obtain a specified percentage of their electricity from renewable sources, commonly referred to as a "renewable portfolio standard" or "RPS." However, as of the date of this report no federal or State of Idaho RPS is in effect. Idaho Power will be required to comply with a five- or ten-percent RPS in Oregon beginning in 2025 (depending on loads at that time), and Idaho Power expects to meet either RPS requirement with Renewable Energy Certificates (REC) obtained from the purchase of power from the Elkhorn Valley wind project.

Pursuant to an IPUC order, Idaho Power is selling its near-term RECs and returning to customers their share (shared 95% with customers in the Idaho jurisdiction) of those proceeds through the PCA. For the years ended December 31, 2015 and 2014, Idaho Power's REC sales totaled $1.8 million and $3.2 million, respectively. The comparative decrease in REC sales resulted primarily from the elimination of a REC purchase and sale agreement with a third party.

Were Idaho Power to be subject to additional RPS legislation, it may cease in full or in part the sale of RECs it receives, seek to obtain RECs from additional projects, generate RECs from any REC-generating facilities it owns or may be required to construct in light of an RPS, or purchase RECs in the market. Historically, Idaho Power has generally not received the RECs associated with PURPA projects. However, an order issued by the IPUC in December 2012, described below, provides that Idaho Power will own a portion of the RECs generated by some PURPA projects. The required purchase of additional RECs to meet RPS requirements would increase Idaho Power's costs, which Idaho Power expects would be wholly or largely passed on to customers through rates and the PCA mechanisms.

Renewable Energy Contracts and PURPA: Idaho Power purchases wind power from both cogeneration and small power production (CSPP) and non-CSPP facilities, including its largest non-CSPP wind power project -- the Elkhorn Valley wind project with a 101 MW nameplate capacity. As of February 5, 2016, Idaho Power had contracts to purchase energy from on-line CSPP wind power projects with a combined nameplate rating of 577 MW and an additional 50 MW of CSPP wind power projects not on-line and scheduled to come on-line by year-end 2016. In addition to its power purchase arrangements with wind power generators, Idaho Power has contracts for the purchase of power from other CSPP and non-CSPP renewable generation sources, such as biomass, solar, small hydroelectric projects, and two geothermal projects. As of February 5, 2016, Idaho Power had contracts to purchase 364 MW of energy from solar projects not yet on-line and 9 MW of energy from hydroelectric projects not yet on-line. All of the solar projects have estimated on-line dates no later than year-end 2016, though with the extension of federal solar tax credit availability, it is likely the on-line date for some of the projects will extend into 2017. The following tables sets forth, as of February 5, 2016, the number and nameplate capacity of Idaho Power's signed CSPP-related agreements. These agreements have original contract terms ranging from one to 35 years.

Status	Number of CSPP Contracts	Nameplate Capacity (MW)
On-line as of February 5, 2016	109	784
Contracted and projected to come on-line by June 1, 2017	28	423

Pursuant to the requirements of PURPA, the IPUC and OPUC have each issued orders and rules regulating Idaho Power's purchase of power from CSPP facilities. A key component of the PURPA power purchase contracts is the energy price contained within the agreements. Regulatory-mandated execution of PURPA agreements can result in Idaho Power acquiring energy that it does not need to serve customer loads at above wholesale market prices and require additional operational integration measures, thus increasing costs to Idaho Power's customers. Integration of these sources of power into Idaho Power's portfolio does not eliminate Idaho Power's need to construct facilities and infrastructure that provide reliable power. For instance, at the time Idaho Power reached its all-time system peak demand of 3,407 MW on July 2, 2013, wind resources on Idaho Power's system, representing roughly 675 MW of nameplate capacity (including non-PURPA wind) were contributing only 57 MW of power due to lack of wind. As the volume of CSPP purchases increases under PURPA, the magnitude of the costs and integration issues also increases. Substantially all PURPA power purchase costs are recovered through base rates and Idaho Power's PCA mechanisms, and thus the primary impact of PURPA agreements is on customer rates.

In light of the volume of intermittent generation Idaho Power is required to purchase pursuant to existing PURPA power purchase agreements and the substantial increase in volume of proposed new solar generation facilities seeking power purchase agreements with Idaho Power, in January 2015 Idaho Power filed an application with the IPUC requesting that the IPUC issue an order directing that the maximum required term for prospective PURPA power purchase agreements be reduced from 20 years to two years. In its application, Idaho Power stated that the requested modification to terms of PURPA energy purchases is necessary to prevent harm to Idaho Power's customers that may result from entering into additional long-term, fixed-rate purchase agreements when Idaho Power predicts that there is no need for new generation capacity through 2021. In February 2015, the IPUC issued an order reducing the maximum contract term of certain future PURPA power purchase agreements from 20 years to five years during the pendency of the proceedings. In August 2015, the IPUC issued an order reducing the length of PURPA contracts that involve avoided-cost-based pricing to two years.

For the Oregon jurisdiction, on April 24, 2015, Idaho Power made filings with the OPUC requesting, among other things, a reduction in the term of standard PURPA power purchase agreements from 20 years to two years for projects above 100 kW, and a temporary suspension of Idaho Power's obligation to enter into new fixed-price standard PURPA agreements during the pendency of the proceedings. On June 23, 2015, the OPUC issued an order denying Idaho Power’s request for a temporary suspension but reduced the eligibility cap for standard contracts from 10 MW to 3 MW on a temporary basis during the pendency of the proceedings. The current phases in these proceedings have been fully submitted and are awaiting a ruling by the OPUC.

ENVIRONMENTAL MATTERS

Overview

Idaho Power is subject to a broad range of federal, state, regional, and local laws and regulations designed to protect, restore, and enhance the environment, including the Clean Air Act (CAA), the CWA, the Resource Conservation and Recovery Act, the Toxic Substances Control Act, the Comprehensive Environmental Response, Compensation and Liability Act, and the Endangered Species Act (ESA), among other laws. These laws are administered by a number of federal, state, and local agencies. In addition to imposing continuing compliance obligations and associated costs, these laws and regulations provide authority to regulators to levy substantial penalties for noncompliance, injunctive relief, and other sanctions. Idaho Power's three co-owned coal-fired power plants and three natural gas-fired combustion turbine power plants are subject to many of these regulations. Idaho Power's 17 hydroelectric projects are also further subject to a number of water discharge standards and other environmental requirements.

Compliance with current and future environmental laws and regulations may:

- increase the operating costs of generating plants;
- increase the construction costs and lead time for new facilities;
- require the modification of existing generating plants, which could result in additional costs;
- require the curtailment or shut-down of existing generating plants; or
- reduce the output from current generating facilities.

Current and future environmental laws and regulations will increase the cost of operating fossil fuel-fired generation plants and constructing new generation and transmission facilities, in large part through the substantial cost of permitting activities and the required installation of additional pollution control devices. In many parts of the United States, some higher-cost, high-emission coal-fired plants have ceased operation or the plant owners have announced a near-term cessation of operation, as the cost of compliance makes the plants uneconomical to operate. The decision to agree to cease operation of the Boardman coal-fired plant, in which Idaho Power owns a 10 percent interest, by the end of 2020, was based in part on the significant future cost of compliance with environmental laws and regulations.

In addition to increasing costs generally, these environmental laws and regulations could affect IDACORP's and Idaho Power's results of operations and financial condition if the costs associated with these environmental requirements and early plant retirements cannot be fully recovered in rates on a timely basis. Part I, Item 1 - "Business - Utility Operations - *Environmental Regulation and Costs*" in this report includes a summary of Idaho Power's expected capital and operating expenditures for environmental matters during the period from 2016 to 2018. Given the uncertainty of future environmental regulations and technological advances, Idaho Power is unable to predict its environmental-related expenditures beyond 2018, though they could be substantial.

Endangered Species Act Matters

Overview: The listing of a species of fish, wildlife, or plants as threatened or endangered under the ESA may have an adverse impact on Idaho Power's ability to construct generation, transmission, or distribution facilities or relicense or operate its hydroelectric facilities. When a species is added to the federal list of threatened and endangered species, it is protected from "take," which is defined to include harming the species. The ESA directs that, concurrent with a designation of a threatened or endangered species, and where prudent and determinable, the applicable agencies also designate "any habitat of such species which is then considered to be critical habitat." The ESA also provides that each federal agency must ensure that any action they authorize, fund, or carry out is not likely to jeopardize the continued existence of a listed species or result in the destruction or adverse modification of its critical habitat. If an action is determined to result in adverse modification of critical habitat, the federal agency must adopt changes to the proposed action to avoid the adverse modification. These changes are often quite extensive and can affect the size, scope, and even the feasibility of a project moving forward. In February 2016, the USFWS and the NMFS issued a set of regulatory and policy changes relating to critical habitat and adverse modification determinations under the ESA. While the ultimate impact of implementation of those changes is yet to be determined, taken as a whole, Idaho Power believes that the changes could result in the applicable agencies having greater authority in making designations of critical habitat and could increase the likelihood of adverse modification determinations.

The construction of generation, transmission, or distribution facilities and the relicensing of Idaho Power's hydroelectric projects can be federally authorized actions that fall under the ESA. There are a number of threatened or endangered species within Idaho Power's service area and within or near proposed transmission line routes, including the slickspot peppergrass and the Washington ground squirrel. Further, there are a number of ESA-listed fish and other aquatic species located in waterways in which Idaho Power has hydroelectric facilities, including fall Chinook salmon, bull trout, Bliss Rapids snail, and Snake River physa snail. To date, efforts to protect these and other listed species have not significantly affected generation levels or operating costs at any of Idaho Power's hydroelectric facilities. However, the ongoing relicensing of the HCC presents endangered species and fisheries issues that may require operational adjustments and could adversely impact the amount of output from hydroelectric dams, potentially causing Idaho Power to rely on more expensive sources for power generation or market purchases.

Non-Listing of Greater Sage Grouse: In 2010, the U.S. Fish and Wildlife Service announced that listing of the greater sage grouse as threatened or endangered under the Endangered Species Act was warranted but precluded by higher priority listing actions. Due to the presence of sage grouse in the vicinity of the Boardman-to-Hemingway and Gateway West 500-kV transmission lines, siting of these projects has required more extensive, costly, and time consuming evaluation, permitting, and engineering. Listing of the greater sage grouse as threatened or endangered would have resulted in the need for a Section 7 consultation under the Endangered Species Act, increasing the cost and time requirements for the permitting of these transmission projects. After evaluating scientific and other information regarding the greater sage-grouse, the U.S. Fish and Wildlife Service determined in September 2015 that protection for the greater sage-grouse under the Endangered Species Act is no longer warranted and withdrew the species from the candidate species list. This determination does not reduce the scope or magnitude of the consideration of sage grouse issues, or possible mitigation requirements associated with sage grouse, in Idaho Power's separate permitting processes for the transmission lines. It does, however, eliminate the requirement for a Section 7 consultation with the U.S. Fish and Wildlife Service under the ESA.

ESA Issues Related to Specific Projects:

Hells Canyon Relicensing Project: In 2007, the FERC requested initiation of formal consultation under the ESA with the NMFS and the USFWS regarding potential effects of HCC relicensing on several listed aquatic and terrestrial species. Formal consultation has yet to be initiated and the NMFS and the USFWS continue to gather and consider information relative to the effects of relicensing on relevant ESA listed species. Idaho Power continues to cooperate with the USFWS, the NMFS, and the FERC in an effort to address ESA concerns. In December 2004, Idaho Power and eleven other parties, including NMFS and the USFWS, entered into an interim agreement that addresses the effects of the ongoing operations of the HCC on ESA listed species pending the relicensing of the project. At the conclusion of formal consultation and with the issuance of biological opinions by the NMFS and the USFWS and an operating license by the FERC, Idaho Power may be required to implement additional measures or further modify or adjust operations to comply with Section 7 of the ESA. The issuance of a final biological opinion during 2016 is unlikely.

Boardman-to-Hemingway and Gateway West Transmission Projects: Slickspot peppergrass was listed as threatened by the USFWS in 2009. In May 2011, the USFWS issued a proposed rule to designate critical habitat for the slickspot peppergrass and proposed to designate approximately 58,000 acres of critical habitat in four southeast Idaho counties. Most of the species is located on federal land. Additionally, the Washington ground squirrel is considered a “candidate species” under the ESA. The existence of slickspot peppergrass and Washington ground squirrel within or near the proposed routes for the Boardman-to-Hemingway and Gateway West projects is impacting, and Idaho Power expects it to continue to impact, the cost and timing of permitting and construction of the projects. The listing of either species would result in the need for a Section 7 consultation under the ESA, which would increase the cost of obtaining permits for the project and could further delay the in-service date of the project.

Climate Change and the Regulation of Greenhouse Gas (GHG) Emissions

Overview: Long-term climate change could significantly affect Idaho Power's business in a variety of ways, including:

- changes in temperature and precipitation could affect customer demand and energy loads;
- extreme weather events could increase service interruptions, outages, maintenance costs, and the need for additional backup systems, and can affect the supply of, and demand for, electricity and natural gas, which may impact the price of those and other commodities;
- changes in the amount and timing of snowpack and stream flows could adversely affect hydroelectric generation;
- legislative and/or regulatory developments related to climate change could affect plants and operations, including restrictions on the construction of new generation resources, the expansion of existing resources, or the operation of generation resources; and

- consumer preference for, and resource planning decisions requiring, renewable or low GHG-emitting sources of energy could impact usage of existing generation sources and require significant investment in new generation and transmission infrastructure.

Federal and state regulations pertaining to GHG emissions under the CAA have raised uncertainty about the future viability of fossil fuels, specifically coal, as an economical energy source for new and existing electric generation facilities because many new technologies for reducing CO_2 emissions from coal, including carbon capture and storage, are still in the development stage and are not yet proven. Stringent emissions standards could result in significant increases in capital expenditures and operating costs, which may accelerate the retirement of coal-fired units and create power system reliability issues. Some higher-cost, high-emission coal-fired plants have ceased operation or the plant owners have announced a near-term cessation of operation, as the cost of compliance makes the plants uneconomical to operate, particularly in light of relatively low natural gas prices that decrease the cost to operate natural gas-fired power plants.

A variety of factors contribute to the financial, regulatory, and logistical uncertainties related to GHG reductions. These include the specific GHG emissions limits imposed, the timing of implementation of these limits, the level of emissions allowances allocated and the level that must be purchased, the purchase price of emissions allowances, the development and commercial availability of technologies for renewable energy and for the reduction of emissions, the degree to which offsets may be used for compliance, provisions for cost containment (if any), the impact on coal and natural gas prices, and the timing and amount of cost recovery through rates. Accordingly, Idaho Power cannot predict the effect on its results of operations, financial position, or cash flows of any GHG emission or other climate change requirements that may be adopted, although the costs to implement and comply with any such requirements could be substantial. A more detailed discussion of legislative and regulatory developments related to climate change follows.

National GHG Initiatives; Final Rule Under CAA Section 111(d): The EPA has become increasingly active in the regulation of GHGs. The EPA's endangerment finding in 2009 that GHGs threaten public health and welfare resulted in the enactment of a series of EPA regulations to address GHG emissions.

In May 2010, the EPA issued the “Tailoring Rule,” which set thresholds for GHG emissions that define when permits are required for new and existing industrial facilities. The final rule “tailors” the requirements of these CAA permitting programs to limit which facilities will be required to obtain PSD and Title V permits. The rules require the use of "best available control technology" for GHG emissions if a new major source or modification of an existing major source is projected to result in GHG emissions of at least 75,000 tons per year (CO_2 equivalent). In addition, Title V permit renewals or modifications for existing major sources must include applicable requirements relating to GHGs. While the rules are complex, Idaho Power believes that its owned and co-owned fossil fuel-fired generation plants are, as of the date of this report, in compliance with the GHG Tailoring Rule.

In June 2014, the EPA released, under Section 111(d) of the CAA, a proposed rule for addressing greenhouse gas emissions from existing fossil fuel-fired electric generating units (EGUs). According to the EPA, the proposed rule was designed to achieve a 30 percent reduction in CO_2 emissions from the power sector. The EPA's proposal required that states meet their respective goals by 2030. On August 3, 2015, the EPA released the final rule under Section 111(d) of the CAA, referred to as the Clean Power Plan. The final rule contains several changes from the proposed rule. The final rule requires states to adopt plans to collectively reduce 2005 levels of power sector CO_2 emissions by 32% by the year 2030. The final rule provides states until September 2018 to submit implementation plans and until 2022 (rather than 2020 under the proposed rule) to begin achieving emissions reductions.

In the final rule, the EPA used a procedure to determine the "best system of emission reduction" that was different than under the proposed rule, establishing two sets of uniform emissions rates (one for coal-fired EGUs and one for natural gas-fired EGUs) and developing state limits based on the number and type of affected EGUs in each state. For the final rule, the EPA analyzed emissions reductions that affected EGUs could achieve by applying three “building blocks,” that the EPA concluded met the statutory standard “best system of emission reduction”:

- Building Block 1: Improving heat rate at existing coal-fired steam EGUs;
- Building Block 2: Shifting electricity generation from higher-emitting coal-fired steam EGUs to lower-emitting existing natural gas combined cycle generation; and
- Building Block 3: Shifting generation from affected fossil fuel-fired EGUs to new zero-emitting renewable energy generation.

The EPA also changed its approach to calculating the emissions targets. In the final rule, the EPA specified nationwide "sub-category" CO_2 emission performance standards applicable to affected steam coal-fired EGUs (1,305 lbs/MWh) and stationary natural gas combustion turbines (771 lbs/MWh). There are a number of methods states may use to achieve compliance. States may simply require affected EGUs to meet these emission rate standards. As in the proposed rule, the EPA also calculated statewide target emission rates, though the method used to calculate the state targets was different in the final rule. The EPA also included equivalent mass-based limits (in short tons) for each state, with the intent of making it easier for states to adopt intrastate or interstate allowance-based emissions trading programs. Other modifications to the proposed rule included an allowance for increased use of thermal generation due to hydroelectric plant variability, and adjustments for plants like the Langley Gulch natural gas power plant that commenced commercial operations during 2012.

Idaho Power's owned and co-owned generation facilities are in the states of Idaho, Nevada, Oregon, and Wyoming. Idaho Power is evaluating the impact that the final rule will have on its operations in those states. Idaho Power is working with state representatives, neighboring utilities, and others as it analyzes the rule and prepares for compliance. However, because the rule is premised on state implementation plans, the terms of which Idaho Power does not control, as of the date of this report Idaho Power is unable to determine the financial or operational impacts of the final rule. Further, on February 9, 2016, the U.S. Supreme Court issued an order staying the implementation of the rule pending the completion of certain legal challenges, which has an uncertain impact on the ultimate timeline for implementation of the rule. In its 2015 IRP, Idaho Power included a number of scenarios for the potential outcome of the then-pending 111(d) rulemaking process, and in the future will continue to make operational decisions based on the implementation of the final rule and any compliance deadlines ultimately imposed.

State GHG Initiatives and Idaho Power's Voluntary GHG Reduction Initiative: In August 2007, the Oregon legislature enacted legislation setting goals of reducing GHG levels to 10 percent below 1990 levels by 2020 and at least 75 percent below 1990 levels by 2050. Oregon imposes GHG emission reporting requirements on facilities emitting 2,500 metric tons or more of CO_2 equivalent annually. The Boardman coal-fired power plant located in Oregon, in which Idaho Power is a 10-percent owner, is subject to and in compliance with Oregon's GHG reporting requirements but is scheduled to cease coal-fired operations in 2020.

The State of Idaho has not passed legislation specifically regulating GHGs, but in May 2007 Idaho's Governor issued Executive Order 2007-05, which directed the Idaho Department of Environmental Quality to work with the state government to implement GHG reductions within each agency, complete a statewide emissions inventory, and provide recommendations to the Governor, among other tasks. Wyoming and Nevada similarly have not enacted legislation to regulate GHG emissions and do not have a reporting requirement, but they are members of the Climate Registry, a national, voluntary GHG emission reporting system. The Climate Registry is a collaboration aimed at developing and managing a common GHG emission reporting system across states, provinces, and tribes to track GHG emissions nationally. All states for which Idaho Power has traditional fuel generating plants (i.e. Idaho, Oregon, Wyoming, and Nevada) are members of the Climate Registry. Idaho Power is engaged in voluntary GHG emissions intensity reduction efforts, which is discussed in Part I, Item 1 - "Business - Utility Operations - *Environmental Regulation and Costs*."

Clean Air Act Matters

Overview: In addition to the CAA developments related to GHG emissions described above, several other regulatory programs developed under the CAA apply to Idaho Power. These include the final Mercury and Air Toxics Standards (MATS), National Ambient Air Quality Standards (NAAQS), NSR/PSD Rules, and the Regional Haze Rule.

MATS Implementation: The final Mercury and Air Toxics Standards (MATS) rule under the CAA, previously referred to as the Utility MACT Rule, was issued in February 2012. The final rule established emission limits for hazardous air pollutants from new and existing coal-fired and oil-fired steam electric generating units. The MATS rule provided that sources must be in compliance with emission limits by April 2015. Idaho Power and the plant co-owners have installed mercury continuous emission monitoring systems on all of the coal-fired units at the Jim Bridger, Boardman, and North Valmy coal-fired generating plants, along with control technology to reduce mercury, acid gases, and particulate matter emissions for purposes of compliance with the MATS rule. Idaho Power believes that as of the date of this report the coal-fired plants are in compliance with the MATS rule. Legal challenges relating to the MATS rule, to which Idaho Power is not a party and pursuant to which the EPA is performing a court-mandated cost analysis for the rule, are pending.

National Ambient Air Quality Standards: The CAA requires the EPA to set ambient air quality standards for six "criteria" pollutants considered harmful to public health and the environment. These six pollutants are carbon monoxide, lead, ozone, particulate matter, nitrogen dioxide, and sulfur dioxide. States are then required to develop emission reduction strategies through State Implementation Plans, or SIPs, based on attainment of these ambient air quality standards. Recent developments and pending actions related to certain of those items relevant to Idaho Power include the following:

- *NO_x*. In 2010, the EPA adopted a new NAAQS for NO_x at a level of 100 parts per billion averaged over a 1-hour period. In connection with the new NAAQS, in February 2012 the EPA issued a final rule designating all of the counties in Idaho, Nevada, Oregon, and Wyoming where Idaho Power owns or has an interest in a natural gas or coal-fired power plant as "unclassifiable/attainment" for NO_x. The EPA indicated it will review the designations after 2015, when three years of air quality monitoring data are available, and may formally designate the counties as attainment or non-attainment for NO_x. A designation of non-attainment may increase the likelihood that Idaho Power would be required to install costly pollution control technology at one or more of its plants. As the designations have not yet been finalized, as of the date of this report Idaho Power is unable to predict the impact of the NAAQS for NO_x on its operations. However, the costs of installation and implementation of any additional pollution reduction technology could be substantial.

- *SO_2*. In 2010, the EPA adopted a new NAAQS for SO_2 at a level of 75 parts per billion averaged over a one-hour period. In 2011, the states of Idaho, Nevada, Oregon, and Wyoming sent letters to the EPA recommending that all counties in these states be classified as "unclassifiable" under the new one-hour SO_2 NAAQS because of a lack of definitive monitoring and modeling data. In February 2013, the EPA issued letters to the states of Idaho and Oregon, finding that the most recent air quality data for those states showed no violations of the 2010 SO_2 standard. As a result, the EPA is waiting to propose designation actions for those states, and is likely to proceed with designation actions once additional data are gathered. Idaho Power expects that designations for Nevada and Wyoming will also be addressed in a separate future action.

- *Ozone*. In late 2014, the EPA issued a proposed rule that would update the ozone standard under the CAA, from 75 parts per billion over an eight-hour period to 65 to 70 parts per billion over an eight-hour period. On October 1, 2015, the EPA issued a final rule lowering the national ozone standard under the CAA to 70 parts per billion. The EPA stated that the vast majority of U.S. counties will meet the standards by 2025 with federal and state rules and programs now in place or underway. The EPA's plan provides for finalizing non-attainment designations in 2017, and it plans to propose rules and guidance over the next year to help states with potential non-attainment areas implement the revised standards. Non-attainment areas will have until 2020 to late 2037 to meet the new standard, with attainment dates varying based on the ozone level in the area. Due to high levels of background ozone, which can be caused by factors such as elevation, vegetation, wildfire, and international transport, attainment in areas within the Intermountain West may be difficult, and the formulation of state implementation plans to bring an area into compliance with the new standard may be challenging due to the existence of ozone caused by factors outside of local control. If the EPA were to make non-attainment determinations in areas where Idaho Power owns or co-owns power plants, or proposes to construct power plants, the state implementation plan for those areas could result in changes to the nature and frequency of operation of existing generation plants and make more difficult or costly the construction of new power generation plants. However, as the EPA has not yet made attainment and non-attainment designations, Idaho Power is unable to predict the potential impact of the standard on its operations. Idaho Power will seek to work with state regulators on implementation plans for any non-attainment areas, in an effort to reduce the potential adverse impact on Idaho Power's operation of its existing power generation plants and construction of future facilities.

Because the EPA has not yet completed the designation of areas as attaining or not attaining the NAAQS for NO_x, SO_2, and ozone, Idaho Power is unable to predict what impact the adoption and implementation of these standards may have on its operations, though it does expect at least some increases in capital and operating costs from the standards if areas in which Idaho Power operate, or adjacent areas, receive non-attainment designations.

Regional Haze Rules: In accordance with federal regional haze rules under the CAA, coal-fired utility boilers are subject to regional haze - best available retrofit technology (RH BART) if they were built between 1962 and 1977 and affect any "Class I" (wilderness) areas. This includes all four units at the Jim Bridger and the Boardman coal-fired plants. The RH BART rules would have required installation of a suite of emissions controls at the Boardman plant; however, in December 2010 the Oregon Environmental Quality Commission approved a plan to install a less costly suite of environmental controls and cease coal-fired operations at the Boardman power plant no later than December 31, 2020.

In December 2009, the Wyoming Department of Environmental Quality (WDEQ) issued a RH BART permit to PacifiCorp as the operator of the Jim Bridger plant. As part of the WDEQ's long term strategy for regional haze, the permit requires that PacifiCorp install SCR equipment for NO_x control at Jim Bridger units 3 and 4 by December 31, 2015 and December 31, 2016, respectively, and submit an application by December 31, 2017 to install add-on NO_x controls at Jim Bridger unit 2 by 2021 and unit 1 by 2022. In November 2010, PacifiCorp and the WDEQ signed a settlement agreement under which PacifiCorp agreed to the timing and nature of the controls. The settlement agreement was conditioned on the EPA ultimately approving those portions of the Wyoming Regional Haze SIP that are consistent with the terms of the settlement agreement. On January 10, 2014, the EPA approved Wyoming's Regional Haze SIP as to the Jim Bridger plant, with the NO_x control compliance dates set forth in the settlement agreement. Several interested parties have appealed the EPA's decisions on Wyoming's RH SIP on various grounds. Idaho Power has not appealed the EPA's decisions but has intervened in the proceedings to participate if and to the extent the Jim Bridger plant could be affected.

New Source Review / Prevention of Significant Deterioration: NSR/PSD is a pre-construction permitting program that requires a stationary source of air pollution to obtain a permit before beginning construction. The purpose of the program is to ensure that air quality is not significantly degraded by the addition of new and modified facilities, industrial boilers, and power plants. Under current NSR provisions of the CAA, any facility that emits regulated pollutants is required to obtain a permit from the EPA or a state regulatory equivalent before beginning the construction of a stationary source that will emit regulated pollutants, or before modifying an existing stationary source that will increase its emission levels. Since 1999, the EPA and the U.S. Department of Justice have been pursuing a national enforcement initiative focused on the compliance status of coal-fired power plants with the NSR permitting requirements and NSPS under the CAA. This initiative has resulted in both enforcement litigation and significant settlements with a large number of public utilities and other owners of coal-fired power plants across the country. As part of an industry-wide assessment of compliance with NSR and NSPS, EPA has sought information from a number of utilities regarding their coal-fired generating facilities. In 2003, the EPA sent information requests pursuant to the CAA to the Jim Bridger plant, seeking information relevant to NSR and NSPS compliance. Additional requests were received by the Boardman plant in 2008, with a follow up request for information in 2009 and by the Valmy plant in 2009. In September 2010, the EPA issued a Notice of Violation to Portland General Electric Company, the operator of the Boardman plant, alleging that Portland General Electric Company violated the NSPS under Section 111 of the CAA and operating permit requirements under Title V of the CAA at the Boardman coal-fired plant as a result of certain modifications made to the plant in 1998 and 2004. To date, the EPA has not taken action on the Notice of Violation, and a related private lawsuit under the CAA was settled in 2011.

Regulation of Coal Combustion Residuals

The Resource Conservation and Recovery Act (RCRA) is a federal statute regulating the generation, treatment, storage, and disposal of solid and hazardous wastes. In December 2014, the EPA signed a final rule for the disposal of coal combustion residuals (CCRs), which are regulated under the RCRA. The rule established structural integrity design criteria and requires that owners and operators of coal-fired power plants periodically conduct a number of structural integrity related assessments and install monitoring apparatus. The final rule also imposes location restrictions on impoundments, requires the closure of impoundments that cannot meet the location restrictions, imposes liner design criteria and operating requirements, and imposes certain record keeping and notification requirements. Additionally, the EPA's rule imposed obligations associated with the closure of CCR impoundments. Idaho Power and its co-owners of coal-fired units performed engineering and cost studies to determine the impacts of the rule, and during 2015 Idaho Power recorded an increase of approximately $5 million in its asset retirement obligation for the Jim Bridger coal-fired plant. The amounts recorded for asset retirement obligations for Idaho Power's other jointly-owned coal-fired plants were not impacted by the EPA's new rule.

Clean Water Act Matters

Definition of "Waters of the United States" Under the CWA: On August 28, 2015, the EPA's and U.S. Army Corps of Engineers' final rule defining the phrase "waters of the United States" under the CWA became effective. Idaho Power believes that the final rule potentially expands federal jurisdiction under the CWA beyond traditional navigable waters, interstate waters, territorial seas, tributaries, and adjacent wetlands, to a number of other waters, including waters with a "significant nexus" to those traditional waters. As a result of the potential expansion, the final rule may result in additional permitting and regulatory requirements under multiple provisions of the CWA. Idaho Power has analyzed the final rule and expects that while it may incur additional permitting and other costs associated with the rule, the aggregate amount of increased costs is unlikely to have a material adverse effect on Idaho Power's operations or financial condition, in part due to the relatively arid climate of Idaho Power's service area and the existing application of the CWA to most of Idaho Power's facilities, including its hydroelectric plants.

On October 9, 2015, the United States Court of Appeals for the Sixth Circuit issued a nationwide stay of the final waters of the United States rule from becoming effective. In response to the Sixth Circuit's decision, the EPA resumed nationwide use of the agency's prior regulations defining the term "waters of the United States." The EPA stated that those regulations will be implemented as they were prior to August 27, 2015, by applying relevant case law, applicable policy, and the best science and technical data on a case-by-case basis in determining which waters are protected by the Clean Water Act.

Regulation of Cooling Water Intake Structures: The CWA generally prohibits the discharge of any "pollutant" from a point source into waters of the United States without a permit. Pollutants are broadly defined to include changes in temperature. Section 316(b) of the CWA requires that National Pollutant Discharge Elimination System permits for facilities with cooling water intake structures ensure that the location, design, construction, and capacity of the structures employ the best technology available (BTA) to minimize harmful impacts on the environment, such as the removal of fish, fish larvae, marine mammals, and other aquatic organisms from waters of the U.S. In May 2014, the EPA issued final rules that establish requirements under Section 316(b) of the CWA for existing power generation facilities that withdraw more than 2 million gallons per day of water from waters of the U.S. and use at least 25 percent of the water they withdraw exclusively for cooling purposes. Given the nature of its co-owned coal-fired plants, Idaho Power expects that its cost to comply with the new rules will be nominal at the Jim Bridger power plant and that it will incur no costs related to the rule at the North Valmy and Boardman plants.

Idaho Power is also addressing CWA issues associated with the relicensing of its HCC. See "Relicensing of Hydroelectric Projects" in this MD&A for additional information on the impact of the CWA on that relicensing effort.

Effluent Limitation Guidelines and Standards: In June 2013, the EPA issued proposed rulemaking to revise the technology-based effluent limitation guidelines and standards under the CWA for water discharged from steam electric power plants, which includes coal-fired plants. On September 30, 2015, the EPA issued the final rule, which established limits on the levels of specified metals in wastewater that can be discharged from steam electric power plants. The EPA stated that it estimates that approximately 12 percent of steam electric power plants will incur some costs associated with the final rule. Idaho Power has analyzed the final rule and, given the nature of its co-owned coal-fired plants, as of the date of this report does not anticipate that the rule will materially affect Idaho Power's operations or financial condition.

November 2015 Presidential Memorandum

On November 3, 2015, President Obama issued a Presidential Memorandum directing the Departments of Defense, Interior and Agriculture, the Environmental Protection Agency, and all bureaus or agencies within them to avoid and then minimize harmful effects to land, water, wildlife, and other ecological resources caused by land- or water-disturbing activities, and to ensure that any remaining harmful effects are effectively addressed, consistent with existing mission and legal authorities. The Presidential Memorandum requires agencies to adopt clear and consistent approaches for avoiding, minimizing, or compensating for impacts of agency activities and activities agencies approve under their jurisdiction. The agencies also are required to develop institutionalized steps for implementing the Presidential Memorandum's policy objectives.

For mitigation, agencies are advised to adopt a "net benefit goal" for natural resource use, along with at least a "no net loss" policy of natural resources affected by federal actions, including permitting. The PM prescribes the application of a mitigation hierarchy consisting of first avoiding, then minimizing, and finally compensating for impacts of applicable activities with a federal nexus. Idaho Power expects that the relevant agencies will issue policies and guidelines during the next two years. The policies and guidelines may result in additional costs associated with construction and maintenance activities on federal lands, including transmission projects. To the extent Idaho Power operations affect any natural resources on federal lands, whether fish, wildlife, or plants, the company could face strict standards of "no net loss," which could significantly increase costs depending on the type of resource impacted, such as listed species under the Endangered Species Act.

Review of Federal Coal Leases

On January 15, 2016, the U.S. Department of the Interior announced that it would launch a comprehensive review to identify and evaluate potential reforms to the federal coal lease program. The review is intended to address questions such as how, when, and where to lease coal resources, how to account for the environmental and public health impacts of federal coal production, and how to ensure taxpayers are earning a fair return for the use of the coal resources. The U.S. Department of the Interior stated that it will not issue new coal leases during the pendency of the review, except under limited circumstances, but mining under existing leases will not be suspended during the review. The Bridger Coal Mine, which mines and supplies coal to the Jim Bridger coal-fired power plant, currently leases its coal under a federal coal lease. Any sizable expansion of the Bridger Coal Mine beyond its current leases is unlikely to occur during the U.S. Department of the Interior's coal lease review. Idaho Power believes that BCC has adequate reserves under existing leases to satisfy its coal delivery obligations to the Jim Bridger plant during the term of the existing coal supply contract through 2024, and that the Jim Bridger plant will otherwise have access to sufficient coal supplies for its operation for the foreseeable future. However, depending on the outcome of the Department of the Interior's review, the availability of coal resources could decline and the cost of leases for coal resources could increase, which could increase the fuel cost for each of Idaho Power's co-owned coal-fired plants.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

When preparing financial statements in accordance with generally accepted accounting principles (GAAP), IDACORP's and Idaho Power's management must apply accounting policies and make estimates that affect the reported amounts of assets, liabilities, revenues, and expenses and related disclosure of contingent assets and liabilities. These estimates often involve judgment about factors that are difficult to predict and are beyond management's control. Management adjusts these estimates based on historical experience and on other assumptions and factors that are believed to be reasonable under the circumstances. Actual amounts could materially differ from the estimates. Management believes the accounting policies and estimates discussed below are the most critical to the portrayal of their financial condition and results of operations and require management's most difficult, subjective, or complex judgments, often as a result of the need to make estimates about the effect of matters that are inherently uncertain and may change in subsequent periods.

Accounting for Rate Regulation

Entities that meet specific conditions are required by GAAP to reflect the impact of regulatory decisions in their consolidated financial statements and to defer certain costs as regulatory assets until matching revenues can be recognized. Similarly, certain items may be deferred as regulatory liabilities. Idaho Power must satisfy three conditions to apply regulatory accounting: (1) an independent regulator must set rates; (2) the regulator must set the rates to cover specific costs of delivering service; and (3) the service territory must lack competitive pressures to reduce rates below the rates set by the regulator.

Idaho Power has determined that it meets these conditions, and its financial statements reflect the effects of the different rate-making principles followed by the jurisdictions regulating Idaho Power. The primary effect of this policy is that Idaho Power had recorded $1.4 billion of regulatory assets and $418 million of regulatory liabilities at December 31, 2015. Idaho Power expects to recover these regulatory assets from customers through rates and refund these regulatory liabilities to customers through rates, but recovery or refund is subject to final review by the regulatory bodies. If future recovery or refund of these amounts ceases to be probable, or if Idaho Power determines that it no longer meets the criteria for applying regulatory accounting, or if accounting rules change to no longer provide for regulatory assets and liabilities, Idaho Power could be required to eliminate those regulatory assets or liabilities. Either circumstance could have a material effect on Idaho Power's financial condition or results of operations.

Income Taxes

IDACORP and Idaho Power use judgment and estimation in developing the provision for income taxes and the reporting of tax-related assets and liabilities. The interpretation of tax laws can involve uncertainty, since tax authorities may interpret such laws differently. Actual income taxes could vary from estimated amounts and may result in favorable or unfavorable impacts to net income, cash flows, and tax-related assets and liabilities.

Idaho Power 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 for other items are provided for the temporary differences between the income tax and financial accounting treatment of such items. Unless contrary to applicable income tax guidance, deferred income taxes are not provided for those income tax temporary differences where the prescribed regulatory accounting methods, or flow-through, direct Idaho Power to recognize the tax impacts currently for rate making and financial reporting.

Refer to Note 1 - "Summary of Significant Accounting Policies" and Note 2 - "Income Taxes" to the consolidated financial statements included in this report for additional information relating to income taxes.

Pension and Other Postretirement Benefits

Idaho Power maintains a tax-qualified, noncontributory defined benefit pension plan covering most employees, an unfunded nonqualified deferred compensation plan for certain senior management employees and directors called the Security Plan for Senior Management Employees (SMSP), and a postretirement benefit plan (consisting of health care and death benefits).

The costs IDACORP and Idaho Power record for these plans depend on the provisions of the plans, changing employee demographics, actual returns on plan assets, and several assumptions used in the actuarial valuations from which the expense is derived. The key actuarial assumptions that affect expense are the expected long-term return on plan assets and the discount rate used in determining future benefit obligations. Management evaluates the actuarial assumptions on an annual basis, taking into account changes in market conditions, trends, and future expectations. Estimates of future stock market performance, changes in interest rates, and other factors used to develop the actuarial assumptions are uncertain, and actual results could vary significantly from the estimates.

The assumed discount rate is based on reviews of market yields on high-quality corporate debt. Specifically, IDACORP and Idaho Power determined the discount rate for each plan through the construction of hypothetical portfolios of bonds selected from high-quality corporate bonds available as of December 31, 2015, with maturities matching the projected cash outflows of the plans. Based on the results of this analysis, the discount rate used to calculate the 2016 pension expense will be increased to 4.60 percent from the 4.25 percent used in 2015.

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, and Idaho Power believes the result provides a reasonable prediction of future investment performance. Additional analysis is performed to measure the expected range of returns, as well as worst-case and best-case scenarios. Based on the current interest rate environment, current rate-of-return expectations are lower than the nominal returns generated over the past 20 years when interest rates were generally much higher. The long-term rate of return used to calculate the 2016 pension expense will be 7.5 percent, the same assumption as was used for 2015. The long-term rate of return used in 2014 was 7.75 percent

Gross net periodic pension and other postretirement benefit cost for these plans totaled $51 million, $32 million, and $55 million for the years ended December 31, 2015, 2014, and 2013, respectively, including amounts deferred as regulatory assets (see discussion below) and amounts allocated to capitalized labor. For 2016, gross pension and other postretirement benefit costs are expected to total approximately $54 million, which takes into account the change in the discount rate noted above.

Had different actuarial assumptions been used, pension expense could have varied significantly. The following table reflects the sensitivities associated with changes in the discount rate and rate-of-return on plan assets actuarial assumptions on historical and future pension and postretirement expense:

	Discount rate		Rate of return	
	2016	**2015**	**2016**	**2015**
	(millions of dollars)			
Effect of 0.5% rate increase on net periodic benefit cost	$ (6.9)	$ (7.2)	$ (2.9)	$ (2.9)
Effect of 0.5% rate decrease on net periodic benefit cost	7.6	8.0	2.9	3.0

Additionally, a 0.5 percent increase in the plans' discount rates would have resulted in a $69 million decrease in the combined benefit obligations of the plans as of December 31, 2015. A 0.5 percent decrease in the plans' discount rates would have resulted in an $78 million increase in the combined benefit obligations of the plans as of December 31, 2015.

The IPUC has authorized Idaho Power to account for its defined benefit pension plan expense on a cash basis, and to defer and account for accrued pension expense as a regulatory asset. The IPUC acknowledged that it is appropriate for Idaho Power to seek recovery in its revenue requirement of reasonable and prudently incurred pension expense based on actual cash contributions. In 2007, Idaho Power began deferring pension expense to a regulatory asset account to be matched with revenue when future pension contributions are recovered through rates. At December 31, 2015, a total of $86 million of expense was deferred as a regulatory asset. Approximately $24 million is expected to be deferred in 2016. Idaho Power recorded pension expense in 2015, 2014, and 2013 of $19 million, $35 million, and $36 million, respectively.

Refer to Note 11 – "Benefit Plans" to the consolidated financial statements included in this report for additional information relating to pension and postretirement benefit plans.

Contingent Liabilities

An estimated loss from a loss contingency is charged to income if (a) it is probable that a liability had been incurred at the date of the financial statements and (b) the amount of the loss can be reasonably estimated. If a probable loss cannot be reasonably estimated, no accrual is recorded but disclosure of the contingency, if material, in the notes to the financial statements is required. Gain contingencies are not recorded until realized. IDACORP and Idaho Power have a number of unresolved issues related to regulatory and legal matters. If the recognition criteria have been met, liabilities have been recorded. Estimates of this nature are highly subjective and the final outcome of these matters could vary significantly from the amounts that have been included in the financial statements.

RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

In May 2014, the Financial Accounting Standards Board (FASB) 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, 2017, including interim periods within that reporting period, with early adoption permitted one year earlier. 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. IDACORP and Idaho Power are currently evaluating the impact of ASU 2014-09 on their financial statements.

In February 2015, the FASB issued ASU 2015-02, *Consolidation (Topic 810) - Amendments to the Consolidation Analysis,* which revises the consolidation model that reporting entities use when determining what entities are to be consolidated. The amendment focus on limited partnerships and similar legal entities, and is effective for interim and annual reporting periods beginning after December 31, 2015. IDACORP and Idaho Power do not believe the impact of ASU 2015-02 on their financial statements will be significant.

In January 2016, the FASB issued ASU 2016-01, *Financial Instruments—Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities,* which revises the accounting related to the classification and measurement of investments in equity securities and the presentation of certain fair value changes for financial liabilities measured at fair value. It also amends certain disclosure requirements associated with the fair value of financial instruments. The new standard is effective for fiscal years beginning after December 15, 2017, including interim periods therein. IDACORP and Idaho Power are currently evaluating the impact of ASU 2016-01 on their financial statements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

IDACORP and Idaho Power are exposed to market risks, including changes in interest rates, changes in commodity prices, credit risk, and equity price risk. The following discussion summarizes these risks and the financial instruments, derivative instruments, and derivative commodity instruments sensitive to changes in interest rates, commodity prices, and equity prices that were held at December 31, 2015. IDACORP has not entered into any of these market-risk-sensitive instruments for trading purposes.

Interest Rate Risk

IDACORP and Idaho Power manage interest expense and short- and long-term liquidity through a combination of fixed rate and variable rate debt. Generally, the amount of each type of debt is managed through market issuance, but interest rate swap and cap agreements with highly-rated financial institutions may be used to achieve the desired combination.

***Variable Rate Debt*:** As of December 31, 2015, IDACORP and Idaho Power had $33.2 million and $14.2 million, respectively, in net floating rate debt. The fair market value of this debt was a respective $33.2 million and $14.2 million. Assuming no change in financial structure, if variable interest rates were to average one percentage point higher than the average rate on December 31, 2015, annual interest expense would increase and pre-tax earnings would decrease by approximately $0.3 million for IDACORP and $0.1 million for Idaho Power.

***Fixed Rate Debt*:** As of December 31, 2015, IDACORP and Idaho Power had $1.7 billion in fixed rate debt, with a fair market value equal to $1.8 billion. These instruments are fixed rate and, therefore, do not expose the companies to a loss in earnings due to changes in market interest rates. However, the fair value of these instruments would increase by approximately $246 million if market interest rates were to decline by one percentage point from their December 31, 2015 levels.

Commodity Price Risk

IDACORP's exposure to changes in commodity prices is related to Idaho Power's ongoing utility operations that produce electricity to meet the demand of its retail electric customers. These effects of changes in commodity prices on Idaho Power are mitigated in large part by Idaho Power's Idaho and Oregon PCA mechanisms. To supplement its generation resources and balance its supply of power with the demand of its retail customers, Idaho Power participates in the wholesale marketplace. These purchased power arrangements allow Idaho Power to respond to fluctuations in the demand for electricity and variability in generating plant operations. Idaho Power also enters into arrangements for the purchase of fuel for natural gas and coal-fired generating plants. These contracts for the purchase of power and fuel expose Idaho Power to commodity price risk.

A number of factors associated with the structure and operation of the energy markets influence the level and volatility of prices for energy commodities and related derivative products. The weather is a major uncontrollable factor affecting the local and regional demand for electricity and the availability and cost of power generation. Other factors include the occurrence and timing of demand peaks due to seasonal, daily, and hourly power demand; power supply; power transmission capacity; changes in federal and state regulation and compliance obligations; fuel supplies; and market liquidity.

The primary objectives of Idaho Power’s energy purchase and sale activity are to meet the demand of retail electric customers, to maintain appropriate physical reserves to ensure reliability, and to make economic use of temporary surpluses that may develop. Idaho Power has adopted a risk management program, which has been reviewed and accepted by the IPUC, designed to reduce exposure to power supply cost-related uncertainty, further mitigating commodity price risk. Idaho Power’s Energy Risk Management Policy (Policy) and associated standards implementing the Policy describe a collaborative process with customers and regulators via a committee called the Customer Advisory Group (CAG). The Risk Management Committee (RMC), comprised of selected Idaho Power officers and other senior staff, oversees the risk management program. The RMC is responsible for communicating the status of risk management activities to the Idaho Power Board of Directors and to the CAG, and Idaho Power’s Audit Committee is responsible for approving the Policy and associated standards. The RMC is also responsible for conducting an ongoing general assessment of the appropriateness of Idaho Power’s strategies for energy risk management activities. In its risk management process, Idaho Power considers both demand-side and supply-side options consistent with its IRP. The primary tools for risk mitigation are physical and financial forward power transactions and fueling alternatives for utility-owned generation resources. Idaho Power only engages in a nominal amount of trading activity for non-retail purposes.

The Policy requires monitoring monthly volumetric electricity position and total monthly dollar (net power supply cost) exposure on a rolling 18-month forward view. The power supply business unit produces and evaluates projections of the operating plan based on factors such as forecasted resource availability, stream flows, and load, and orders risk mitigating actions, including resource optimization and hedging strategies, dictated by the limits stated in the Policy to bring exposures within pre-established risk guidelines. The RMC evaluates the actions initiated by power supply for consistency and compliance with the Policy. Idaho Power representatives meet with the CAG at least annually to assess effectiveness of the limits. Changes to the limits can be endorsed by the CAG and referred to the board of directors for approval.

Credit Risk

IDACORP is subject to credit risk based on Idaho Power's activity with market counterparties. Idaho Power is exposed to this risk to the extent that a counterparty may fail to fulfill a contractual obligation to provide energy, purchase energy, or complete financial settlement for market activities. Idaho Power mitigates this exposure by actively establishing credit limits; measuring, monitoring, and reporting credit risk using appropriate contractual arrangements; and transferring of credit risk through the use of financial guarantees, cash, or letters of credit. Idaho Power maintains a current list of acceptable counterparties and credit limits.

The use of performance assurance collateral in the form of cash, letters of credit, or guarantees is common industry practice. Idaho Power maintains margin agreements relating to its wholesale commodity contracts that allow performance assurance collateral to be requested of and/or posted with certain counterparties. As of December 31, 2015, Idaho Power had posted $0.9 million performance assurance collateral. Should Idaho Power experience a reduction in its credit rating on Idaho Power’s unsecured debt to below investment grade Idaho Power could be subject to requests by its wholesale counterparties to post additional performance assurance collateral. Counterparties to derivative instruments and other forward contracts could request immediate payment or demand immediate ongoing full daily collateralization on derivative instruments and contracts in net liability positions. Based upon Idaho Power’s energy and fuel portfolio and market conditions as of December 31, 2015, the amount of collateral that could be requested upon a downgrade to below investment grade was approximately $11.6 million. To minimize capital requirements, Idaho Power actively monitors the portfolio exposure and the potential exposure to additional requests for performance assurance collateral calls through sensitivity analysis.

Idaho Power is obligated to provide service to all electric customers within its service area. Credit risk for Idaho Power’s retail customers is managed by credit and collection policies that are governed by rules issued by the IPUC or OPUC. Idaho Power records a provision for uncollectible accounts, based upon historical experience, to provide for the potential loss from nonpayment by these customers. Idaho Power continuously monitors levels of nonpayment from customers and makes any necessary adjustments to its provision for uncollectible accounts accordingly.

Idaho utility customer relations rules prohibit Idaho Power from terminating electric service during the months of December through February to any residential customer who declares that he or she is unable to pay in full for utility service and whose household includes children, elderly, or infirm persons. Idaho Power’s provision for uncollectible accounts could be affected by changes in future prices as well as changes in IPUC or OPUC regulations.

Equity Price Risk

IDACORP is exposed to price fluctuations in equity markets, primarily through Idaho Power's defined benefit pension plan assets, a mine reclamation trust fund owned by an equity-method investment of Idaho Power, and other equity security investments at Idaho Power. The equity securities held by the pension plan and in such accounts are diversified to achieve broad market participation and reduce the impact of any single investment, sector, or geographic region. Idaho Power has established asset allocation targets for the pension plan holdings, which are described in Note 11 - "Benefit Plans" to the consolidated financial statements included in this report. Idaho Power has invested a significant portion of its $24.5 million of financial instruments classified as available-for-sale securities in exchange traded short-term bond funds. A hypothetical 5 percent increase in interest rates would result in an approximate $2.4 million decrease in the fair value of available-for-sale securities as of December 31, 2015.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Financial Statements and Financial Statement Schedules

All other schedules have been omitted because they are not required, not applicable, or the required information is otherwise included.

IDACORP, Inc.
Consolidated Statements of Income

	Year Ended December 31,		
	2015	2014	2013
	(thousands of dollars except for per share amounts)		
Operating Revenues:			
Electric utility:			
General business	$ 1,151,038	$ 1,122,281	$ 1,101,728
Off-system sales	30,887	77,165	54,473
Other revenues	85,580	79,205	86,897
Total electric utility revenues	1,267,505	1,278,651	1,243,098
Other	2,784	3,873	3,116
Total operating revenues	1,270,289	1,282,524	1,246,214
Operating Expenses:			
Electric utility:			
Purchased power	226,470	244,628	220,579
Fuel expense	186,231	201,241	214,482
Power cost adjustment	16,766	22,235	(39,537)
Other operations and maintenance	342,146	354,567	348,867
Energy efficiency programs	30,532	27,154	35,636
Depreciation	138,110	132,987	129,735
Taxes other than income taxes	32,808	31,748	30,561
Total electric utility expenses	973,063	1,014,560	940,323
Other	15,129	14,268	14,149
Total operating expenses	988,192	1,028,828	954,472
Operating Income	282,097	253,696	291,742
Allowance for Equity Funds Used During Construction	21,785	17,931	14,858
Earnings of Unconsolidated Equity-Method Investments	11,128	12,372	11,939
Other Income, Net	7,159	6,328	17,013
Interest Expense:			
Interest on long-term debt	83,056	80,562	81,492
Other interest	8,922	7,703	7,203
Allowance for borrowed funds used during construction	(10,044)	(8,464)	(7,663)
Total interest expense, net	81,934	79,801	81,032
Income Before Income Taxes	240,235	210,526	254,520
Income Tax Expense	45,760	16,772	72,226
Net Income	194,475	193,754	182,294
Adjustment for loss (income) attributable to noncontrolling interests	204	(274)	123
Net Income Attributable to IDACORP, Inc.	$ 194,679	$ 193,480	$ 182,417
Weighted Average Common Shares Outstanding - Basic (000's)	50,220	50,131	50,052
Weighted Average Common Shares Outstanding - Diluted (000's)	50,292	50,199	50,126
Earnings Per Share of Common Stock:			
Earnings Attributable to IDACORP, Inc. - Basic	$ 3.88	$ 3.86	$ 3.64
Earnings Attributable to IDACORP, Inc. - Diluted	$ 3.87	$ 3.85	$ 3.64

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Statements of Comprehensive Income

	Year Ended December 31,		
	2015	**2014**	**2013**
	(thousands of dollars)		
Net Income	$ 194,475	$ 193,754	$ 182,294
Other Comprehensive Income:			
Unrealized gains (losses) on securities:			
Unrealized holding gains arising during the year, net of tax of $0, $0 and $1,894	—	—	2,951
Reclassification adjustment for gains included in net income, net of tax of $0, $0 and $4,550	—	—	(7,087)
Net unrealized losses	—	—	(4,136)
Unfunded pension liability adjustment, net of tax of $1,851 $(4,881), and $3,016	2,882	(7,605)	4,699
Total Comprehensive Income	197,357	186,149	182,857
Comprehensive loss (income) attributable to noncontrolling interests	204	(274)	123
Comprehensive Income Attributable to IDACORP, Inc.	$ 197,561	$ 185,875	$ 182,980

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Balance Sheets

	December 31,	
	2015	2014
	(thousands of dollars)	
Assets		
Current Assets:		
Cash and cash equivalents	$ 114,802	$ 56,808
Receivables:		
Customer (net of allowance of $1,196 and $1,960, respectively)	73,505	79,083
Other (net of allowance of $159 and $144, respectively)	8,642	16,018
Income taxes receivable	13,058	11,867
Accrued unbilled revenues	65,805	56,270
Materials and supplies (at average cost)	56,924	55,404
Fuel stock (at average cost)	61,818	55,171
Prepayments	17,979	18,476
Deferred income taxes	—	42,359
Current regulatory assets	49,215	50,042
Other	288	603
Total current assets	462,036	442,101
Investments	140,743	165,424
Property, Plant and Equipment:		
Utility plant in service	5,485,464	5,248,212
Accumulated provision for depreciation	(1,913,927)	(1,841,011)
Utility plant in service - net	3,571,537	3,407,201
Construction work in progress	396,931	401,930
Utility plant held for future use	7,090	7,090
Other property, net of accumulated depreciation	16,855	17,256
Property, plant and equipment - net	3,992,413	3,833,477
Other Assets:		
American Falls and Milner water rights	11,592	13,698
Company-owned life insurance	48,566	23,893
Regulatory assets	1,305,210	1,192,345
Long-term receivables (net of allowance of $552 and $552, respectively)	22,538	6,317
Other	40,216	23,782
Total other assets	1,428,122	1,260,035
Total	$ 6,023,314	$ 5,701,037

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Balance Sheets

	December 31, 2015	December 31, 2014
	(thousands of dollars)	
Liabilities and Equity		
Current Liabilities:		
Current maturities of long-term debt	$ 1,064	$ 1,064
Notes payable	20,000	31,300
Accounts payable	95,526	89,324
Taxes accrued	10,762	10,367
Interest accrued	22,292	22,630
Accrued compensation	42,961	43,774
Current regulatory liabilities	2,217	11,400
Advances from customers	31,214	17,204
Other	16,270	14,718
Total current liabilities	242,306	241,781
Other Liabilities:		
Deferred income taxes	1,137,375	1,065,290
Regulatory liabilities	416,282	390,207
Pension and other postretirement benefits	394,030	403,334
Other	45,867	44,238
Total other liabilities	1,993,554	1,903,069
Long-Term Debt	1,725,410	1,598,622
Commitments and Contingencies		
Equity:		
IDACORP, Inc. shareholders' equity:		
Common stock, no par value (shares authorized 120,000,000; 50,352,051 and 50,308,702 shares issued, respectively)	849,112	845,402
Retained earnings	1,230,105	1,132,237
Accumulated other comprehensive loss	(21,276)	(24,158)
Treasury stock (11,221 and 38,764 shares at cost, respectively)	(57)	(280)
Total IDACORP, Inc. shareholders' equity	2,057,884	1,953,201
Noncontrolling interests	4,160	4,364
Total equity	2,062,044	1,957,565
Total	$ 6,023,314	$ 5,701,037

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Statements of Cash Flows

	Year Ended December 31,		
	2015	2014	2013
	(thousands of dollars)		
Operating Activities:			
Net income	$ 194,475	$ 193,754	$ 182,294
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	142,581	137,088	133,776
Deferred income taxes and investment tax credits	38,645	19,163	65,568
Changes in regulatory assets and liabilities	13,699	32,135	(25,581)
Pension and postretirement benefit plan expense	30,207	44,627	45,907
Contributions to pension and postretirement benefit plans	(42,843)	(33,720)	(33,393)
Earnings of unconsolidated equity-method investments	(11,128)	(12,372)	(11,939)
Distributions from unconsolidated equity-method investments	12,458	5,261	17,526
Allowance for equity funds used during construction	(21,785)	(17,931)	(14,858)
Gain on sale of investments and assets	(97)	(193)	(11,678)
Other non-cash adjustments to net income, net	2,788	5,085	3,297
Change in:			
Accounts receivable	4,740	20,433	(29,557)
Accounts payable and other accrued liabilities	2,440	6,359	(517)
Taxes accrued/receivable	818	(13,631)	4,747
Other current assets	(14,861)	(13,124)	(12,165)
Other current liabilities	403	1,771	1,819
Other assets	3,021	(3,655)	(830)
Other liabilities	(2,367)	(6,707)	(8,867)
Net cash provided by operating activities	353,194	364,343	305,549
Investing Activities:			
Additions to property, plant and equipment	(294,021)	(274,094)	(246,674)
Payments received from transmission project joint funding partners	11,377	—	11,364
Purchase of available-for-sale securities	(14,106)	(8,000)	(32,661)
Proceeds from sale of available-for-sale securities	34,243	—	25,661
Purchase of life insurance investment	(30,000)	—	—
Other	801	9,674	5,717
Net cash used in investing activities	(291,706)	(272,420)	(236,593)
Financing Activities:			
Issuance of long-term debt	250,000	—	150,000
Retirement of long-term debt	(121,064)	(1,064)	(71,064)
Dividends on common stock	(96,810)	(88,489)	(78,832)
Net change in short-term borrowings	(11,300)	(23,450)	(14,950)
Issuance of common stock	—	195	255
Acquisition of treasury stock	(3,277)	(2,737)	(2,124)
Make-whole premium on retirement of long-term debt	(17,872)	—	—
Other	(3,171)	2,268	(606)
Net cash used in financing activities	(3,494)	(113,277)	(17,321)
Net increase (decrease) in cash and cash equivalents	57,994	(21,354)	51,635
Cash and cash equivalents at beginning of the year	56,808	78,162	26,527
Cash and cash equivalents at end of the year	$ 114,802	$ 56,808	$ 78,162
Supplemental Disclosure of Cash Flow Information:			
Cash paid during the year for:			
Income taxes	$ 8,857	$ 11,364	$ 1,437
Interest (net of amount capitalized)	$ 79,442	$ 77,295	$ 77,968
Non-cash investing activities:			
Additions to property, plant and equipment in accounts payable	$ 23,840	$ 28,438	$ 24,246

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Statements of Equity

	Year Ended December 31,		
	2015	2014	2013
	(thousands of dollars)		
Common Stock:			
Balance at beginning of year	$ 845,402	$ 839,750	$ 834,922
Issued	—	195	255
Other	3,710	5,457	4,573
Balance at end of year	849,112	845,402	839,750
Retained Earnings:			
Balance at beginning of year	1,132,237	1,027,461	923,981
Net income attributable to IDACORP, Inc.	194,679	193,480	182,417
Common stock dividends ($1.92, $1.76, and $1.57 per share, respectively)	(96,811)	(88,704)	(78,937)
Balance at end of year	1,230,105	1,132,237	1,027,461
Accumulated Other Comprehensive (Loss) Income:			
Balance at beginning of year	(24,158)	(16,553)	(17,116)
Net unrealized holding loss on securities (net of tax)	—	—	(4,136)
Unfunded pension liability adjustment (net of tax)	2,882	(7,605)	4,699
Balance at end of year	(21,276)	(24,158)	(16,553)
Treasury Stock:			
Balance at beginning of year	(280)	(8)	(21)
Issued	3,500	2,465	2,137
Acquired	(3,277)	(2,737)	(2,124)
Balance at end of year	(57)	(280)	(8)
Total IDACORP, Inc. shareholders’ equity at end of year	2,057,884	1,953,201	1,850,650
Noncontrolling Interests:			
Balance at beginning of year	4,364	4,090	4,213
Net (loss) income attributable to noncontrolling interests	(204)	274	(123)
Balance at end of year	4,160	4,364	4,090
Total equity at end of year	$ 2,062,044	$ 1,957,565	$ 1,854,740

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Statements of Income

	Year Ended December 31,		
	2015	2014	2013
	(thousands of dollars)		
Operating Revenues:			
General business	$ 1,151,038	$ 1,122,281	$ 1,101,728
Off-system sales	30,887	77,165	54,473
Other revenues	85,580	79,205	86,897
Total operating revenues	1,267,505	1,278,651	1,243,098
Operating Expenses:			
Operation:			
Purchased power	226,470	244,628	220,579
Fuel expense	186,231	201,241	214,482
Power cost adjustment	16,766	22,235	(39,537)
Other operations and maintenance	342,146	354,567	348,867
Energy efficiency programs	30,532	27,154	35,636
Depreciation	138,110	132,987	129,735
Taxes other than income taxes	32,808	31,748	30,561
Total operating expenses	973,063	1,014,560	940,323
Income from Operations	294,442	264,091	302,775
Other Income (Expense):			
Allowance for equity funds used during construction	21,785	17,931	14,858
Earnings of unconsolidated equity-method investments	9,773	10,814	10,242
Other (expense) income, net	(5,071)	(4,363)	5,772
Total other income	26,487	24,382	30,872
Interest Charges:			
Interest on long-term debt	83,056	80,562	81,492
Other interest	8,706	7,472	6,817
Allowance for borrowed funds used during construction	(10,044)	(8,464)	(7,663)
Total interest charges	81,718	79,570	80,646
Income Before Income Taxes	239,211	208,903	253,001
Income Tax Expense	48,228	19,516	76,260
Net Income	$ 190,983	$ 189,387	$ 176,741

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Statements of Comprehensive Income

	Year Ended December 31,		
	2015	2014	2013
	(thousands of dollars)		
Net Income	$ 190,983	$ 189,387	$ 176,741
Other Comprehensive Income:			
Unrealized gains (losses) on securities:			
Unrealized holding gains arising during the year, net of tax of $0, $0 and $1,894	—	—	2,951
Reclassification adjustment for gains included in net income, net of tax of $0, $0 and $4,550	—	—	(7,087)
Net unrealized losses	—	—	(4,136)
Unfunded pension liability adjustment, net of tax of $1,851 $(4,881), and $3,016	2,882	(7,605)	4,699
Total Comprehensive Income	$ 193,865	$ 181,782	$ 177,304

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Balance Sheets

	December 31, 2015	December 31, 2014
	(thousands of dollars)	
Assets		
Electric Plant:		
In service (at original cost)	$ 5,485,464	$ 5,248,212
Accumulated provision for depreciation	(1,913,927)	(1,841,011)
In service - net	3,571,537	3,407,201
Construction work in progress	396,931	401,930
Held for future use	7,090	7,090
Electric plant - net	3,975,558	3,816,221
Investments and Other Property	121,267	142,825
Current Assets:		
Cash and cash equivalents	110,756	46,695
Receivables:		
Customer (net of allowance of $1,196 and $1,960, respectively)	73,505	79,083
Other (net of allowance of $159 and $144, respectively)	8,520	15,890
Income taxes receivable	5,432	20,428
Accrued unbilled revenues	65,805	56,270
Materials and supplies (at average cost)	56,924	55,404
Fuel stock (at average cost)	61,818	55,171
Prepayments	17,846	18,356
Current regulatory assets	49,215	50,042
Other	288	603
Total current assets	450,109	397,942
Deferred Debits:		
American Falls and Milner water rights	11,592	13,698
Company-owned life insurance	48,566	23,893
Regulatory assets	1,305,210	1,192,345
Other	56,533	23,937
Total deferred debits	1,421,901	1,253,873
Total	$ 5,968,835	$ 5,610,861

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Balance Sheets

	December 31,	
	2015	**2014**
	(thousands of dollars)	
Capitalization and Liabilities		
Capitalization:		
Common stock equity:		
Common stock, $2.50 par value (50,000,000 shares authorized; 39,150,812 shares outstanding)	$ 97,877	$ 97,877
Premium on capital stock	712,258	712,258
Capital stock expense	(2,097)	(2,097)
Retained earnings	1,127,426	1,033,350
Accumulated other comprehensive loss	(21,276)	(24,158)
Total common stock equity	1,914,188	1,817,230
Long-term debt	1,725,410	1,598,622
Total capitalization	3,639,598	3,415,852
Current Liabilities:		
Current maturities of long-term debt	1,064	1,064
Accounts payable	94,970	88,552
Accounts payable to related parties	1,059	2,027
Taxes accrued	10,745	10,329
Interest accrued	22,292	22,630
Accrued compensation	42,835	43,410
Current regulatory liabilities	2,217	11,400
Advances from customers	31,214	17,204
Other	15,506	20,219
Total current liabilities	221,902	216,835
Deferred Credits:		
Deferred income taxes	1,252,371	1,141,755
Regulatory liabilities	416,282	390,207
Pension and other postretirement benefits	394,030	403,334
Other	44,652	42,878
Total deferred credits	2,107,335	1,978,174
Commitments and Contingencies		
Total	$ 5,968,835	$ 5,610,861

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Statements of Cash Flows

	Year Ended December 31,		
	2015	2014	2013
	(thousands of dollars)		
Operating Activities:			
Net income	$ 190,983	$ 189,387	$ 176,741
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	141,972	136,496	133,135
Deferred income taxes and investment tax credits	25,702	15,454	59,355
Changes in regulatory assets and liabilities	13,699	32,135	(25,581)
Pension and postretirement benefit plan expense	30,185	44,579	45,861
Contributions to pension and postretirement benefit plans	(42,821)	(33,672)	(33,347)
Earnings of unconsolidated equity-method investments	(9,773)	(10,814)	(10,242)
Distributions from unconsolidated equity-method investments	10,833	3,586	14,901
Allowance for equity funds used during construction	(21,785)	(17,931)	(14,858)
Gain on sale of investments and assets	(97)	(186)	(11,678)
Other non-cash adjustments to net income, net	(687)	2,087	629
Change in:			
Accounts receivable	1,998	20,072	(31,472)
Accounts payable	2,646	6,183	(397)
Taxes accrued/receivable	17,179	(22,911)	6,740
Other current assets	(14,849)	(13,137)	(12,166)
Other current liabilities	443	1,776	1,721
Other assets	3,021	(3,655)	(831)
Other liabilities	(2,222)	(6,238)	(8,603)
Net cash provided by operating activities	346,427	343,211	289,908
Investing Activities:			
Additions to utility plant	(293,968)	(273,911)	(246,670)
Payments received from transmission project joint funding partners	11,377	—	11,364
Purchase of available-for-sale securities	(14,106)	(8,000)	(32,661)
Proceeds from the sale of available-for-sale securities	34,243	—	25,661
Purchase of life insurance investment	(30,000)	—	—
Other	706	8,508	3,971
Net cash used in investing activities	(291,748)	(273,403)	(238,335)
Financing Activities:			
Issuance of long-term debt	250,000	—	150,000
Retirement of long-term debt	(121,064)	(1,064)	(71,064)
Dividends on common stock	(96,907)	(88,584)	(78,926)
Make-whole premium on retirement of long-term debt	(17,872)	—	—
Other	(4,775)	—	(2,299)
Net cash provided by (used in) financing activities	9,382	(89,648)	(2,289)
Net increase (decrease) in cash and cash equivalents	64,061	(19,840)	49,284
Cash and cash equivalents at beginning of the year	46,695	66,535	17,251
Cash and cash equivalents at end of the year	$ 110,756	$ 46,695	$ 66,535
Supplemental Disclosure of Cash Flow Information:			
Cash paid during the year for:			
Income taxes	$ 7,487	$ 26,116	$ 9,667
Interest (net of amount capitalized)	$ 79,226	$ 77,063	$ 77,583
Non-cash investing activities:			
Additions to property, plant and equipment in accounts payable	$ 23,840	$ 28,438	$ 24,246

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Statements of Retained Earnings

	Year Ended December 31,		
	2015	**2014**	**2013**
	(thousands of dollars)		
Retained Earnings, Beginning of Year	$ 1,033,350	$ 932,547	$ 834,732
Net Income	190,983	189,387	176,741
Dividends on Common Stock	(96,907)	(88,584)	(78,926)
Retained Earnings, End of Year	$ 1,127,426	$ 1,033,350	$ 932,547

The accompanying notes are an integral part of these statements.

IDACORP, INC. AND IDAHO POWER COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

This Annual Report on Form 10-K is a combined report of IDACORP, Inc. (IDACORP) and Idaho Power Company (Idaho Power). Therefore, these Notes to the Consolidated Financial Statements apply to both IDACORP and Idaho Power. However, Idaho Power makes no representation as to the information relating to IDACORP's other operations.

Nature of Business

IDACORP is a holding company formed in 1998 whose principal operating subsidiary is Idaho Power. Idaho Power is an electric utility with a service 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.

IDACORP's other wholly-owned subsidiaries include IDACORP Financial Services, Inc. (IFS), an investor in affordable housing and other real estate investments; Ida-West Energy Company (Ida-West), an operator of small hydroelectric generation projects that satisfy the requirements of the Public Utility Regulatory Policies Act of 1978 (PURPA); and IDACORP Energy Services Co. (IESCo), which is the former limited partner of, and current successor by merger to, IDACORP Energy L.P. (IE), a marketer of energy commodities that wound down operations in 2003.

Principles of Consolidation

IDACORP's and Idaho Power's consolidated financial statements include the assets, liabilities, revenues and expenses of each company and its wholly-owned subsidiaries listed above, as well as any variable interest entities (VIEs) for which the respective company is the primary beneficiary. Investments in VIEs for which the companies are not the primary beneficiaries, but have the ability to exercise significant influence over operating and financial policies, are accounted for using the equity method of accounting.

IDACORP also consolidates one variable interest entity (VIE), Marysville Hydro Partners (Marysville), which is a joint venture owned 50 percent by Ida-West and 50 percent by Environmental Energy Company (EEC). At December 31, 2015, Marysville had approximately $19 million of assets, primarily a hydroelectric plant, and approximately $12 million of intercompany long-term debt, which is eliminated in consolidation. EEC has borrowed amounts from Ida-West to fund a portion of its required capital contributions to Marysville. The loans are payable from EEC's share of distributions from Marysville and are secured by the stock of EEC and EEC's interest in Marysville. Ida-West is identified as the primary beneficiary because the combination of its ownership interest in the joint venture with the intercompany note and the EEC note result in Ida-West's ability to control the activities of the joint ventures. Creditors of Marysville have no recourse to the general credit of IDACORP and there are no other arrangements that could require IDACORP to provide financial support to Marysville or expose IDACORP to losses.

The BCC joint venture is also a VIE, but because the power to direct the activities that most significantly impact the economic performance of BCC is shared with the joint venture partner, Idaho Power is not the primary beneficiary. The carrying value of BCC was $95 million at December 31, 2015, and Idaho Power's maximum exposure to loss is the carrying value, any additional future contributions to BCC, and a $73 million guarantee for mine reclamation costs, which is discussed further in Note 9.

IFS's affordable housing limited partnership and other real estate investments are also VIEs for which IDACORP is not the primary beneficiary. IFS's limited partnership interests range from 5 to 99 percent and were acquired between 1996 and 2010. As a limited partner, IFS does not control these entities and they are not consolidated. IFS's maximum exposure to loss in these developments is limited to its net carrying value, which was $10 million at December 31, 2015.

Ida-West's other investments in PURPA facilities, BCC and IFS's investments are accounted for under the equity method of accounting (see Note 14).

Except for amounts related to sales of electricity by Ida-West's PURPA projects to Idaho Power, all intercompany transactions and balances have been eliminated in consolidation.

The accompanying consolidated financial statements include Idaho Power's proportionate share of utility plant and related operations resulting from its interests in jointly owned plants (see Note 12).

Management Estimates

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

System of Accounts

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

Regulation of Utility Operations

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 IDACORP's and Idaho Power's results of operations and financial condition.

IDACORP's and Idaho Power's financial statements reflect the effects of the different ratemaking principles followed by the jurisdictions regulating Idaho Power. The application of accounting principles related to regulated operations sometimes results in Idaho Power recording expenses and revenues in a different period than when an unregulated enterprise would record such expenses and revenues. In these instances, the amounts are deferred or accrued 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.

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

There were no impaired receivables without related allowances at December 31, 2015 and 2014. 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. In addition, regulatory mechanisms in place in Idaho and Oregon affect the reported amount of revenue. See Note 3 for additional discussion of certain of the following mechanisms:

- energy efficiency riders to fund energy efficiency program expenditures. Expenditures funded through the rider are reported as an operating expense with an equal amount of revenues recorded in other revenues;
- a fixed cost adjustment mechanism that results in recording additional or reduced revenue based on the allowed and actual fixed costs recovered through current rates;
- a sharing mechanism providing for refunds to customers for earnings above stated returns on equity in Idaho;
- franchise fees and similar taxes related to energy consumption. None of these collections are reported on the income statement; and
- collection in base rates of 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 deferred 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 2015, 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. 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 long-lived assets in 2015, 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 7.6 percent for 2015, and 7.7 percent for both 2014 and 2013.

Income Taxes

IDACORP and Idaho Power account for income taxes under the asset and liability method, which requires the recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Under this method (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 amortized over the terms of the respective debt issues. Losses on reacquired debt and associated costs are amortized over the life of the associated replacement debt, as allowed under regulatory accounting.

Supplemental Cash Flows Information

In 2015, Idaho Power executed an agreement to exchange property with another electric utility. Under the terms of the agreement, each party transferred to the other transmission-related equipment with a book value of approximately $44 million. Idaho Power received an immaterial amount of cash, representing the difference in the book value of the assets exchanged.

Also in 2015, Idaho Power executed a long-term service agreement and transferred to the service provider approximately $22 million of spare parts in partial exchange for future services. No cash was exchanged in the 2015 transfer transaction.

Reclassifications

Certain prior year amounts on IDACORP's and Idaho Power's consolidated balance sheets and consolidated statements of cash flows have been reclassified to conform to the current year presentation. Advances from customers are now classified in a separate line in current liabilities on the balance sheet. Previously, such amounts were presented in accounts payable or other in current liabilities. Also, payments received from transmission funding joint project partners are now presented in a separate line in investing cash flows on the cash flows statement. Previously, these amounts were netted against additions to property, plant and equipment.

Recently Issued Accounting Pronouncements

In April 2015, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) 2015-03, *Interest - Imputation of Interest (Subtopic 835-30) Simplifying the Presentation of Debt Issuance Costs,* which changed the required balance sheet presentation of debt issuance costs. The ASU requires that debt issuance costs be reported as reductions of long-term debt rather than as long-term assets. As allowed, IDACORP and Idaho Power elected to early-adopt the provisions of this ASU for its December 31, 2015 financial statements; retrospective application is required. Debt issuance costs of $16.5 million and $15.8 million at December 31, 2015 and 2014, respectively, are now reported as reductions of long-term debt. These costs were previously presented as other assets and other deferred debits on IDACORP's and Idaho Power's respective balance sheets. See Note 4 for a discussion of long-term debt.

In November 2015, the FASB issued ASU 2015-17, *Income Taxes (Topic 740) - Balance Sheet Classification of Deferred Taxes,* which requires that all deferred taxes be presented as non-current. As allowed, IDACORP and Idaho Power elected to early-adopt the provisions of this ASU for its December 31, 2015 balance sheets. Also as allowed, prior periods were not retrospectively adjusted.

In May 2014, the FASB issued 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, 2017, including interim periods, with early adoption permitted one year earlier. 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. IDACORP and Idaho Power are currently evaluating the impact of ASU 2014-09 on their financial statements.

In February 2015, the FASB issued ASU 2015-02, *Consolidation (Topic 810) - Amendments to the Consolidation Analysis,* which revises the consolidation model that reporting entities use when determining what entities are to be consolidated. The amendments focus on limited partnerships and similar legal entities, and is effective for interim and annual reporting periods beginning after December 31, 2015. IDACORP and Idaho Power do not believe the impact of ASU 2015-02 on their financial statements will be significant.

In January 2016, the FASB issued ASU 2016-01, *Financial Instruments—Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities,* which revises the accounting related to the classification and measurement of investments in equity securities and the presentation of certain fair value changes for financial liabilities measured at fair value. It also amends certain disclosure requirements associated with the fair value of financial instruments. The new standard is effective for fiscal years beginning after December 15, 2017, including interim periods. IDACORP and Idaho Power are currently evaluating the impact of ASU 2016-01 on their financial statements.

2. INCOME TAXES

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

	IDACORP			Idaho Power		
	2015	2014	2013	2015	2014	2013
			(thousands of dollars)			
Federal income tax expense at 35% statutory rate	$ 84,154	$ 73,588	$ 89,125	$ 83,724	$ 73,116	$ 88,550
Change in taxes resulting from:						
AFUDC	(11,140)	(9,238)	(7,882)	(11,140)	(9,238)	(7,882)
Capitalized interest	2,693	2,278	1,832	2,693	2,278	1,832
Investment tax credits	(2,963)	(3,002)	(3,119)	(2,963)	(3,002)	(3,119)
Removal costs	(4,807)	(3,656)	(3,527)	(4,807)	(3,656)	(3,527)
Capitalized overhead costs	(8,750)	(8,750)	(8,750)	(8,750)	(8,750)	(8,750)
Capitalized repair costs	(28,700)	(26,250)	(19,250)	(28,700)	(26,250)	(19,250)
Bond redemption costs	(6,459)	—	—	(6,459)	—	—
Tax method change – capitalized repairs	—	(24,516)	4,583	—	(24,516)	4,583
State income taxes, net of federal benefit	7,343	4,680	6,730	7,503	5,334	6,970
Depreciation	17,149	16,040	14,820	17,149	16,040	14,820
Affordable housing tax credits	(3,258)	(5,189)	(5,503)	—	—	—
Affordable housing investment amortization	1,519	2,757	1,684	—	—	—
Other, net	(1,021)	(1,970)	1,483	(22)	(1,840)	2,033
Total income tax expense	$ 45,760	$ 16,772	$ 72,226	$ 48,228	$ 19,516	$ 76,260
Effective tax rate	19.0%	8.0%	28.4%	20.2%	9.3%	30.1%

The items comprising income tax expense are as follows:

	IDACORP			Idaho Power		
	2015	2014	2013	2015	2014	2013
			(thousands of dollars)			
Income taxes current:						
Federal	$ 4,831	$ (4,926)	$ 3,416	$ 16,470	$ (2,805)	$ 10,988
State	2,704	3,516	3,241	6,056	6,867	5,917
Total	7,535	(1,410)	6,657	22,526	4,062	16,905
Income taxes deferred:						
Federal	34,770	17,159	61,947	27,696	21,833	60,934
State	626	(3,260)	1,806	(2,486)	(6,421)	(804)
Total	35,396	13,899	63,753	25,210	15,412	60,130
Investment tax credits:						
Deferred	3,455	3,044	2,344	3,455	3,044	2,344
Restored	(2,963)	(3,002)	(3,119)	(2,963)	(3,002)	(3,119)
Total	492	42	(775)	492	42	(775)
Affordable housing investment amortization	2,337	4,241	2,591	—	—	—
Total income tax expense	$ 45,760	$ 16,772	$ 72,226	$ 48,228	$ 19,516	$ 76,260

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

	IDACORP		Idaho Power	
	2015	2014	2015	2014
	(thousands of dollars)			
Deferred tax assets:				
Regulatory liabilities	$ 51,131	$ 55,490	$ 51,131	$ 55,490
Deferred compensation	27,573	25,355	27,489	25,240
Deferred revenue	34,282	28,529	34,282	28,529
Tax credits	147,299	154,044	30,307	26,843
Partnership investments	7,220	8,190	—	—
Retirement benefits	126,885	132,571	126,885	132,571
Other	11,245	15,222	10,745	14,553
Total	405,635	419,401	280,839	283,226
Deferred tax liabilities:				
Property, plant and equipment	474,879	451,118	474,879	451,118
Regulatory assets	875,028	802,188	875,028	802,188
Power cost adjustments	18,489	23,192	18,489	23,192
Partnership investments	16,925	17,492	9,829	10,227
Retirement benefits	126,090	122,360	126,090	122,360
Other	31,600	25,982	28,895	22,252
Total	1,543,011	1,442,332	1,533,210	1,431,337
Net deferred tax liabilities	$ 1,137,376	$ 1,022,931	$ 1,252,371	$ 1,148,111

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.

Tax Credit Carryforwards

As of December 31, 2015, IDACORP had $108.7 million of general business credit and $0.7 million of alternative minimum tax credit carryforwards for federal income tax purposes and $37.9 million of Idaho investment tax credit carryforward. The general business credit carryforward period expires from 2024 to 2035, and the Idaho investment tax credit expires from 2021 to 2029.

Uncertain Tax Positions

IDACORP and Idaho Power believe that they have no material income tax uncertainties for 2015 and prior tax years. Both companies recognize interest accrued related to unrecognized tax benefits as interest expense and penalties as other expense.

IDACORP and Idaho Power are subject to examination by their major tax jurisdictions - U.S. federal and the State of Idaho. The open tax years for examination are 2015 for federal and 2012-2015 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 2015, the IRS completed its examination of IDACORP's 2014 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).

The method change was pursuant to Revenue Procedure 2013-24 and brought 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 incorporated provisions of the final tangible property regulations issued by the U.S. Treasury Department and IRS in 2013 that addressed the deduction or capitalization of expenditures related to tangible property. Following the automatic consent procedures provided for in the Revenue Procedure, Idaho Power adopted this method with the filing of IDACORP’s 2014 consolidated federal income tax return in September 2015. The IRS approved the method change prior to the filing of the return as part of IDACORP’s 2014 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 of 2014. 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 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.

3. REGULATORY MATTERS

IDACORP's and Idaho Power's financial statements reflect the effects of the different ratemaking principles followed by the jurisdictions regulating Idaho Power. Included below is a summary of Idaho Power's regulatory assets and liabilities, as well as a discussion of notable regulatory matters.

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):

	As of December 31, 2015			Total as of December 31,	
Description	Remaining Amortization Period	Earning a Return[1]	Not Earning a Return	2015	2014
Regulatory Assets:					
Income taxes		$ —	$ 875,027	$ 875,027	$ 802,188
Unfunded postretirement benefits[2]		—	251,762	251,762	264,548
Pension expense deferrals		62,642	23,148	85,790	63,644
Energy efficiency program costs[3]		4,482	—	4,482	4,690
Power supply costs[4]	Varies	47,220	—	47,220	59,189
Fixed cost adjustment[4]	2016-2017	36,820	—	36,820	23,737
Asset retirement obligations[5]		—	14,410	14,410	17,309
Mark-to-market liabilities[6]		—	4,973	4,973	3,961
Long-term service agreement[7]	2043	18,592	11,633	30,225	—
Other	2016-2021	1,096	2,620	3,716	3,121
Total		$ 170,852	$ 1,183,573	$ 1,354,425	$ 1,242,387
Regulatory Liabilities:					
Income taxes		$ —	$ 51,131	$ 51,131	$ 55,490
Removal costs[5]		—	183,505	183,505	180,063
Investment tax credits		—	79,655	79,655	79,163
Deferred revenue-AFUDC[8]		58,835	28,855	87,690	72,975
Energy efficiency program costs[3]		6,554	—	6,554	—
Power supply costs[4]		—	—	—	1
Settlement agreement sharing mechanism[4]	2016-2017	3,159	—	3,159	7,999
Mark-to-market assets[6]		—	405	405	1,880
Other		5,219	1,180	6,399	4,036
Total		$ 73,767	$ 344,731	$ 418,498	$ 401,607

(1) Earning a return includes either interest or a return on the investment as a component of rate base at the allowed rate of return.
(2) Represents the unfunded obligation of Idaho Power's pension and postretirement benefit plans, which are discussed in Note 11.
(3) The 2015 energy efficiency asset represents the Oregon jurisdiction balance and the liability represents the Idaho jurisdiction balance. Both jurisdiction's balances were assets at December 31, 2014.
(4) These items are discussed in more detail in this Note 3.
(5) Asset retirement obligations and removal costs are discussed in Note 13.
(6) Mark-to-market assets and liabilities are discussed in Note 16.
(7) A portion not earning a return as of December 31, 2015 will be eligible to earn a return as of January 1, 2018.
(8) Idaho Power is collecting revenue in the Idaho jurisdiction for AFUDC on HCC relicensing costs but is deferring revenue recognition of the amounts collected until the license is issued and the asset is placed in service under the new license.

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 net power supply costs (primarily fuel and purchased power less off-system sales) against net power supply costs being recovered. Under the PCA mechanisms, certain differences between actual net power supply costs incurred by Idaho Power and the costs are recorded as a deferred charge or credit on the balance sheets for future recovery or refund. 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 sales-based adjustment intended to ensure that power supply expense recovery resulting solely from sales changes does not distort the results of the mechanism.

The table below summarizes the three 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, 2015	$ (11.6)	The net decrease in Idaho PCA rates included the application of (a) a customer rate credit of $8.0 million for sharing of revenues with customers for the year 2014 under the terms of the December 2011 settlement stipulation, and (b) $4.0 million of surplus Idaho energy efficiency rider funds.
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. The shifting of base net power supply costs is discussed in more detail 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.

In March 2014, the IPUC issued an order approving Idaho Power's application 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 became effective June 1, 2014. Approval of the order removed the Idaho-jurisdictional portion of those expenses (approximately $99 million) from collection via the Idaho PCA mechanism and instead results in collecting that portion through base rates.

In July 2014, the IPUC opened a docket pursuant to which Idaho Power, the IPUC Staff, and other interested parties further evaluated Idaho Power's application of the true-up component of the PCA mechanism and whether a deferral balance adjustment was appropriate. While the IPUC's docket was closed in August 2014 with no adjustment to the PCA true-up revenue amount, Idaho Power subsequently met with the IPUC Staff to explore approaches to increasing the accuracy of the actual cost recovery under the PCA mechanism. In May 2015, the IPUC approved a settlement stipulation that resulted in the replacement of the existing load-based adjustment used for determining the power cost deferrals under the PCA mechanism with a similar sales-based adjustment. The sales-based adjustment functions in the same manner as the previous load-based adjustment but measures deviations between Idaho-specific test year sales and actual Idaho sales rather than deviations between test year loads and actual loads. The approved settlement stipulation implemented the new methodology as of January 1, 2015.

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 2015, 2014, and 2013 are summarized in the table that follows:

Year and Mechanism	APCU or PCAM Adjustment
2015 PCAM	Actual net power supply costs were within the deadband, resulting in no deferral.
2015 APCU	A rate decrease of $0.7 million annually took effect June 1, 2015.
2014 PCAM	Actual net power supply costs were within the deadband, resulting 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.

Notable Idaho Regulatory Matters

Idaho Base Rate Changes: Idaho base rates were most recently established in 2012, and adjusted in 2014. 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. In June 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 became effective June 1, 2014.

December 2011 Idaho Settlement Stipulation: In December 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 was less than 9.5 percent, then Idaho Power may amortize up to a total of $45 million of additional accumulated deferred investment tax credits (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 exceeded 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 exceeded 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 each of 2012, 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 each of 2012, 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
2012	$7.2	$14.6

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 expense deferral regulatory asset (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.

Idaho Power recorded no additional ADITC amortization and a $3.2 million provision against current revenue for sharing with customers for 2015 under the October 2014 Idaho settlement stipulation, as its Idaho ROE for 2015 was above 10.0 percent.

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 authorized fixed-cost recovery amount and the actual fixed costs recovered by Idaho Power during the year. The annual change in 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 three FCA years:

FCA Year	Period Rates in Effect	Annual Amount (in millions)
2014	June 1, 2015-May 31, 2016	$16.9
2013	June 1, 2014-May 31, 2015	$14.9
2012	June 1, 2013-May 31, 2014	$8.9

In July 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 (including weather-normalization, customer count methodology, rate adjustment cap, and cross-subsidization issues) and whether the FCA is effectively removing Idaho Power's disincentive to aggressively pursue energy efficiency programs. In May 2015, the IPUC approved a settlement stipulation that modified the FCA mechanism by replacing weather-normalized billed sales with actual billed sales in the calculation of the FCA, applicable for the entirety of calendar year 2015 and thereafter, and reflected in FCA charges effective June 1, 2016.

Notable Oregon Regulatory Matters

Oregon Base Rate Changes: Oregon base rates were most recently established in a general rate case in 2012. In February 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, in September 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

Idaho Power uses 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 four most recent annual OATT Final Informational Filings were as follows:

Applicable Period	OATT Rate (per kW-year)
October 1, 2015 to September 30, 2016	$ 23.43
October 1, 2014 to September 30, 2015	$ 22.48
October 1, 2013 to September 30, 2014	$ 22.80
October 1, 2012 to September 30, 2013	$ 21.29

Idaho Power's current OATT rate is based on a net annual transmission revenue requirement of $121.3 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 IDACORP's and Idaho Power's long-term debt at December 31 (in thousands of dollars):

	2015	2014
First mortgage bonds:		
6.025% Series due 2018	$ —	$ 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
3.65% Series Due 2045	250,000	—
Total first mortgage bonds	1,555,000	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	2,127	3,191
Unamortized issuance costs and discounts	(20,998)	(18,850)
Total IDACORP and Idaho Power outstanding debt(2)	1,726,474	1,599,686
Current maturities of long-term debt	(1,064)	(1,064)
Total long-term debt	$ 1,725,410	$ 1,598,622

(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, 2015 to $1.721 billion.
(2) At December 31, 2015 and 2014, the overall effective cost of Idaho Power's outstanding debt was 4.96 percent and 5.19 percent, respectively.

At December 31, 2015, the maturities for the aggregate amount of IDACORP and Idaho Power long-term debt outstanding were as follows (in thousands of dollars):

2016	2017	2018	2019	2020	Thereafter
$ 1,064	$ 1,064	$ —	$ 100,000	$ 230,000	$ 1,415,344

Long-Term Debt Issuances, Maturities, and Availability

On March 6, 2015, Idaho Power issued $250 million in principal amount of 3.65% first mortgage bonds, secured medium-term notes, Series J, maturing on March 1, 2045. On April 23, 2015, Idaho Power redeemed, prior to maturity, $120 million in principal amount of 6.025% first mortgage bonds, medium-term notes, Series H due July 2018. In accordance with the redemption provisions of the notes, the redemption included Idaho Power's payment of a make-whole premium to the holders of the redeemed notes in the aggregate amount of approximately $17.9 million. Idaho Power used a portion of the net proceeds from the March 2015 sale of first mortgage bonds, medium-term notes to effect the redemption.

In April 2013, Idaho Power received orders from the IPUC, OPUC, and Wyoming Public Service Commission (WPSC) authorizing Idaho Power to issue and sell from time to time up to $500 million in aggregate principal amount of debt securities and first mortgage bonds, subject to conditions specified in the orders. Authority from the IPUC was through April 9, 2015. On April 1, 2015, the IPUC approved a two-year extension through April 9, 2017, continuing Idaho Power's authorization to issue and sell from time to time debt securities and first mortgage bonds. 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 seven percent.

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, 2015, $250 million in principal amount of Series J Notes remained available for issuance under the Indenture.

***Mortgage*:** As of December 31, 2015, Idaho Power could issue under its Indenture approximately $1.5 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

On November 6, 2015, IDACORP and Idaho Power entered into Credit Agreements replacing the existing Second Amended and Restated Credit Agreements, dated October 26, 2011, to provide credit facilities that may be used for general corporate purposes and commercial paper backup. IDACORP's credit facility consists of a revolving line of credit not to exceed the aggregate principal amount at any one time outstanding of $100 million, including swingline loans in an aggregate principal amount at any time outstanding not to exceed $10 million, and letters of credit in an aggregate principal amount at any time outstanding not to exceed $50 million. Idaho Power's credit facility consists of a revolving line of credit, through the issuance of loans and standby letters of credit, not to exceed the aggregate principal amount at any one time outstanding of $300 million, including swingline loans in an aggregate principal amount at any time outstanding not to exceed $30 million, and letters of credit in an aggregate principal amount at any time outstanding not to exceed $100 million. IDACORP and Idaho Power have the right to request an increase in the aggregate principal amount of the facilities to $150 million and $450 million, respectively, in each case subject to certain conditions.

The IDACORP and Idaho Power credit facilities have similar terms and conditions. The interest rates for any borrowings under the facilities are based on either (1) a floating rate that is equal to the highest of the prime rate, federal funds rate plus 0.5 percent, or LIBOR rate plus 1.0 percent, or (2) the LIBOR rate, plus, in each case, an applicable margin, provided that the federal funds rate and LIBOR rate will not be less than 0.0 percent. The margin is based on IDACORP's or Idaho Power's, as applicable, senior unsecured long-term indebtedness credit rating by Moody's Investors Service, Inc., Standard and Poor's Ratings Services, and Fitch Rating Services, Inc., as set forth on a schedule to the credit agreements. Under their respective credit facilities, the companies pay a facility fee on the commitment based on the respective company's credit rating for senior unsecured long-term debt securities. The credit facilities mature on November 6, 2020, though IDACORP and Idaho Power may request up to two one-year extensions of the credit agreements, subject to certain conditions.

At December 31, 2015, no loans were outstanding under either IDACORP's or Idaho Power's facilities. At December 31, 2015, 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 IDACORP's and Idaho Power's short-term borrowings were as follows at December 31, 2015 and December 31, 2014:

	IDACORP		Idaho Power		Total	
	2015	2014	2015	2014	2015	2014
Commercial paper balances:						
At the end of year	$ 20,000	$ 31,300	$ —	$ —	$ 20,000	$ 31,300
Average during the year	$ 22,054	$ 37,786	$ —	$ —	$ 22,054	$ 37,786
Weighted-average interest rate						
At the end of the year	0.88%	0.43%	—%	—%	0.88%	0.43%

6. COMMON STOCK

IDACORP Common Stock

The following table summarizes IDACORP common stock transactions during the last three years and shares reserved at December 31, 2015:

	Shares issued			Shares reserved
	2015	2014	2013	December 31, 2015
Balance at beginning of year	50,308,702	50,233,463	50,158,486	
Continuous equity program	—	—	—	3,000,000
Dividend reinvestment and stock purchase plan	—	—	—	2,576,723
Employee savings plan	—	—	—	3,567,954
Long-term incentive and compensation plan	43,349	75,239	74,977	1,424,695
Restricted stock plan	—	—	—	256,154
Balance at end of year	50,352,051	50,308,702	50,233,463	

IDACORP has historically entered into sales agency agreements as a means of selling its common stock from time to time pursuant to a continuous equity program. On July 12, 2013, IDACORP entered into its current Sales Agency Agreement with BNY Mellon Capital Markets, LLC (BNYMCM). Under the agreement, IDACORP may offer and sell up to 3 million shares of its common stock from time to time in at-the-market offerings through BNYMCM as IDACORP's agent. IDACORP has no obligation to issue any minimum number of shares under the Sales Agency Agreement. As of the date of this report, no shares of IDACORP common stock have been issued under the current Sales Agency Agreement.

Restrictions on Dividends

Idaho Power's ability to pay dividends on its common stock held by IDACORP and IDACORP's ability to pay dividends on its common stock are limited to the extent payment of such dividends would violate the covenants in their respective credit facilities or Idaho Power's Revised Code of Conduct. A covenant under IDACORP's credit facility and Idaho Power's credit facility requires IDACORP and Idaho Power to maintain leverage ratios of consolidated indebtedness to consolidated total capitalization, as defined therein, of no more than 65 percent at the end of each fiscal quarter. At December 31, 2015, the leverage ratios for IDACORP and Idaho Power were 46 percent and 48 percent, respectively. Based on these restrictions, IDACORP's and Idaho Power's dividends were limited to $1.1 billion and $980 million, respectively, at December 31, 2015. 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, 2015, IDACORP and Idaho Power were 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, 2015, Idaho Power's common equity capital was 52 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.

7. STOCK-BASED COMPENSATION

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

The LTICP (for officers, key employees, and directors) permits the grant of 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, 2015, the maximum number of shares available under the LTICP and RSP were 1,043,542 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 and the year issued, the final number of shares awarded can range from zero to 150 percent of the target award for awards granted prior to 2015 and from zero to 200 percent of the target award for awards granted in 2015. 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. Idaho Power share amounts represent the portion of IDACORP amounts related to Idaho Power employees:

	IDACORP		Idaho Power	
	Number of Shares	**Weighted-Average Grant Date Fair Value**	**Number of Shares**	**Weighted-Average Grant Date Fair Value**
Nonvested shares at January 1, 2015	255,073	$ 43.90	250,396	$ 43.91
Shares granted	116,781	54.01	115,863	54.05
Shares forfeited	(10,904)	55.32	(10,413)	55.63
Shares vested	(130,130)	36.91	(127,056)	36.84
Nonvested shares at December 31, 2015	230,820	$ 52.41	228,790	$ 52.44

The total fair value of shares vested during the years ended December 31, 2015, 2014, and 2013 was $8.3 million, $6.6 million, and $5.0 million, respectively. At December 31, 2015, IDACORP had $4.7 million of total unrecognized compensation cost related to nonvested share-based compensation that was expected to vest. Idaho Power's share of this amount was $4.7 million. These costs are expected to be recognized over a weighted-average period of 1.68 years. IDACORP uses original issue and/or treasury shares for these awards.

In 2015, a total of 15,324 shares were awarded to directors at a grant date fair value of $62.62 per share. Directors elected to defer receipt of 3,831 of these shares, which are being held as deferred stock units with dividend equivalents reinvested in additional stock units.

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

	IDACORP			Idaho Power		
	2015	**2014**	**2013**	**2015**	**2014**	**2013**
Compensation cost	$ 5,299	$ 5,609	$ 4,888	$ 5,221	$ 5,458	$ 4,783
Income tax benefit	2,072	2,193	1,911	2,042	2,134	1,870

No equity compensation costs have been capitalized.

8. EARNINGS PER SHARE

The following table presents the computation of IDACORP's basic and diluted earnings per share for the years ended December 31, 2015, 2014, and 2013 (in thousands, except for per share amounts):

	Year Ended December 31,		
	2015	2014	2013
Numerator:			
Net income attributable to IDACORP, Inc.	$ 194,679	$ 193,480	$ 182,417
Denominator:			
Weighted-average common shares outstanding - basic	50,220	50,131	50,052
Effect of dilutive securities	72	68	74
Weighted-average common shares outstanding - diluted	50,292	50,199	50,126
Basic earnings per share	$ 3.88	$ 3.86	$ 3.64
Diluted earnings per share	$ 3.87	$ 3.85	$ 3.64

9. COMMITMENTS

Purchase Obligations

At December 31, 2015, Idaho Power had the following long-term commitments relating to purchases of energy, capacity, transmission rights, and fuel (in thousands of dollars):

	2016	2017	2018	2019	2020	Thereafter
Cogeneration and power production	$ 199,156	$ 233,197	$ 241,356	$ 234,772	$ 234,316	$3,592,891
Fuel	60,122	43,276	16,206	9,169	8,833	114,417

As of December 31, 2015, Idaho Power had 784 MW nameplate capacity of PURPA-related projects on-line, with an additional 448 MW nameplate capacity of projects projected to be on-line by June 1, 2017. Of the 448 MW nameplate capacity of projected PURPA-related projects at the end of 2015, as of February 5, 2016, three contracts with solar projects with a combined nameplate capacity of 25 MW had terminated. Termination of the agreements reduced Idaho Power's contractual payment obligations by approximately $74 million over the 20-year lives of the terminated contracts. 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 $131 million in 2015, $145 million in 2014, and $131 million in 2013.

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

	2016	2017	2018	2019	2020	Thereafter
Operating leases	$ 233	$ 971	$ 985	$ 1,062	$ 897	$ 12,625
Equipment, maintenance, and service agreements	48,707	11,703	14,869	9,214	12,095	83,721
FERC and other industry-related fees	12,894	12,746	12,746	8,632	5,942	29,708

IDACORP's expense for operating leases was approximately $4.4 million in 2015, $5.9 million in 2014, and $5.3 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 $73 million at December 31, 2015, 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, 2015, the value of the reclamation trust fund was $70 million. During 2015, the reclamation trust fund distributed approximately $6 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.

IDACORP and Idaho Power enter into financial agreements and power purchase and sale agreements that include indemnification provisions relating to various forms of claims or liabilities that may arise from the transactions contemplated by these agreements. Generally, a maximum obligation is not explicitly stated in the indemnification provisions and, therefore, the overall maximum amount of the obligation under such indemnification provisions cannot be reasonably estimated. IDACORP and Idaho Power periodically evaluate the likelihood of incurring costs under such indemnities based on their historical experience and the evaluation of the specific indemnities. As of December 31, 2015, management believes the likelihood is remote that IDACORP or Idaho Power would be required to perform under such indemnification provisions or otherwise incur any significant losses with respect to such indemnification obligations. Neither IDACORP nor Idaho Power has recorded any liability on their respective consolidated balance sheets with respect to these indemnification obligations.

10. CONTINGENCIES

IDACORP and Idaho Power have in the past and expect in the future to become involved in various claims, controversies, disputes, and other contingent matters, including the items described in this Note 10. Some of these claims, controversies, disputes, and other contingent matters involve litigation and regulatory or other contested proceedings. The ultimate resolution and outcome of litigation and regulatory proceedings is inherently difficult to determine, particularly where (a) the remedies or penalties sought are indeterminate, (b) the proceedings are in the early stages or the substantive issues have not been well developed, or (c) the matters involve complex or novel legal theories or a large number of parties. In accordance with applicable accounting guidance, IDACORP and Idaho Power, as applicable, establish an accrual for legal proceedings when those matters proceed to a stage where they present loss contingencies that are both probable and reasonably estimable. In such cases, there may be a possible exposure to loss in excess of any amounts accrued. IDACORP and Idaho Power monitor those matters for developments that could affect the likelihood of a loss and the accrued amount, if any, and adjust the amount as appropriate. If the loss contingency at issue is not both probable and reasonably estimable, IDACORP and Idaho Power do not establish an accrual and the matter will continue to be monitored for any developments that would make the loss contingency both probable and reasonably estimable. As of the date of this report, IDACORP's and Idaho Power's accruals for loss contingencies are not material to their financial statements as a whole; however, future accruals could be material in a given period. IDACORP's and Idaho Power's determination is based on currently available information, and estimates presented in financial statements and other financial disclosures involve significant judgment and may be subject to significant uncertainty. 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 the western wholesale markets during 2000 and 2001 caused numerous purchasers of electricity in those markets to initiate proceedings to consider requiring refunds and other forms of disgorgement from energy sellers. Some of these proceedings remain pending before the FERC or are on appeal to the United States Court of Appeals for the Ninth Circuit, and thus there remains some uncertainty about the ultimate outcome of the proceedings. Idaho Power and IESCo (as successor to IDACORP Energy L.P.) believe that the current state of the FERC's orders, if maintained, and the settlement releases they have obtained, will restrict potential claims that might result from the pending proceedings. As a result, IDACORP and Idaho Power predict that these matters will not have a material adverse effect on their respective results of operations or financial condition. However, if unanticipated orders are issued by the FERC or by the Ninth Circuit Court of Appeals or other courts, exposure to indirect claims in the proceedings could exist. These indirect claims would consist of 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. Given the speculative nature of ripple claims and in light of Idaho Power's and IESCo participating in the market as both a buyer and seller of energy, Idaho Power and IESCo are unable to estimate the possible loss or range of loss that could result from the proceedings and 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.

Hoku Corporation Bankruptcy Claims

On June 26, 2015, the trustee in the Hoku Corporation chapter 7 bankruptcy case (*In Re: Hoku Corporation*, United States Bankruptcy Court, District of Idaho, Case No. 13-40838 JDP) filed a complaint against Idaho Power, alleging that specified payments made by Hoku Corporation to Idaho Power in the six years prior to Hoku Corporation's bankruptcy filing in July 2013 should be recoverable by the trustee as constructive fraudulent transfers. Hoku Corporation was the parent entity of Hoku Materials, Inc., with which Idaho Power had an electric service agreement approved by the IPUC in March 2009. Under the electric service agreement, Idaho Power agreed to provide electric service to a polysilicon production facility under construction by Hoku Materials in the state of Idaho. Idaho Power also had agreements with Hoku Materials pertaining to the design and construction of apparatus for the provision of electric service to the polysilicon plant. The trustee's complaint against Idaho Power includes alternative causes of action for constructive fraudulent transfer under the federal bankruptcy code, Idaho law, and federal law, with requests for recovery from Idaho Power in amounts up to approximately $36 million. The complaint alleges that the payments made by Hoku Corporation to Idaho Power are subject to recovery by the trustee on the basis that Hoku Corporation was insolvent at the time of the payments and did not have any legal or equitable title in the polysilicon plant or liability for Hoku Materials' debts, and thus did not receive reasonably equivalent value for the payments it made for or on behalf of Hoku Materials.

As of the date of this report, the proceedings are in preliminary stages and it is not possible to determine Idaho Power's potential liability, if any, or to reasonably estimate a possible loss or range of possible loss, if any, within the trustee's alternative prayers for relief. Idaho Power intends to vigorously defend against the claims.

Other Proceedings

IDACORP and Idaho Power are parties 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, record an accrual for associated loss contingencies when they are probable and reasonably estimable. As of the date of this report the companies believe that resolution of those matters will not have a material adverse effect on their respective consolidated financial statements. Idaho Power is also actively monitoring various pending environmental regulations 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. However, Idaho Power does believe that future capital investment for infrastructure and modifications to its electric generating facilities could be significant to comply with these regulations.

11. 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 2015, 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		SMSP	
	2015	2014	2015	2014
Change in projected benefit obligation:				
Benefit obligation at January 1	$ 844,812	$ 695,093	$ 94,410	$ 77,773
Service cost	33,164	25,292	1,689	1,645
Interest cost	35,171	35,415	3,868	3,856
Actuarial (gain) loss	(47,952)	114,496	(352)	15,324
Benefits paid	(29,672)	(25,484)	(4,226)	(4,188)
Projected benefit obligation at December 31	835,523	844,812	95,389	94,410
Change in plan assets:				
Fair value at January 1	559,719	545,092	—	—
Actual return on plan assets	(9,431)	10,111	—	—
Employer contributions	39,000	30,000	—	—
Benefits paid	(29,672)	(25,484)	—	—
Fair value at December 31	559,616	559,719	—	—
Funded status at end of year	$ (275,907)	$ (285,093)	$ (95,389)	$ (94,410)
Amounts recognized in the statement of financial position consist of:				
Other current liabilities	$ —	$ —	$ (4,423)	$ (4,193)
Noncurrent liabilities	(275,907)	(285,093)	(90,966)	(90,217)
Net amount recognized	$ (275,907)	$ (285,093)	$ (95,389)	$ (94,410)
Amounts recognized in accumulated other comprehensive income consist of:				
Net loss	$ 253,212	$ 263,350	$ 34,260	$ 38,808
Prior service cost	74	295	673	857
Subtotal	253,286	263,645	34,933	39,665
Less amount recorded as regulatory asset	(253,286)	(263,645)	—	—
Net amount recognized in accumulated other comprehensive income	$ —	$ —	$ 34,933	$ 39,665
Accumulated benefit obligation	$ 714,994	$ 719,617	$ 86,838	$ 84,684

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 recorded value of these investments was approximately $69.3 million and $65.0 million at December 31, 2015 and 2014, 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			SMSP		
	2015	2014	2013	2015	2014	2013
Service cost	$ 33,164	$ 25,292	$ 31,357	$ 1,689	$ 1,645	$ 2,178
Interest cost	35,171	35,415	31,830	3,868	3,856	3,258
Expected return on assets	(42,310)	(42,289)	(35,755)	—	—	—
Amortization of net loss	13,927	3,911	17,118	4,195	2,618	2,840
Amortization of prior service cost	221	347	347	185	220	212
Net periodic pension cost	40,173	22,676	44,897	9,937	8,339	8,488
Adjustments due to the effects of regulation(1)	(21,173)	12,124	(9,013)	—	—	—
Net periodic benefit cost recognized for financial reporting	$ 19,000	$ 34,800	$ 35,884	$ 9,937	$ 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			SMSP		
	2015	2014	2013	2015	2014	2013
Actuarial (loss) gain during the year	$ (3,790)	$ (146,674)	$ 154,261	$ 353	$ (15,324)	$ 4,664
Reclassification adjustments for:						
Amortization of net loss	13,927	3,911	17,118	4,195	2,618	2,840
Amortization of prior service cost	221	347	347	185	220	212
Adjustment for deferred tax effects	(4,050)	55,678	(67,136)	(1,851)	4,881	(3,017)
Adjustment due to the effects of regulation	(6,308)	86,738	(104,590)	—	—	—
Other comprehensive income recognized related to pension benefit plans	$ —	$ —	$ —	$ 2,882	$ (7,605)	$ 4,699

In 2016, IDACORP and Idaho Power expect to recognize as components of net periodic benefit cost $17.3 million from amortizing amounts recorded in accumulated other comprehensive income (or as a regulatory asset for the pension plan) as of December 31, 2015, relating to the pension plan and SMSP. This amount consists of $13.5 million of amortization of net loss and $0.1 million of amortization of prior service cost for the pension plan, and $3.5 million of amortization of net loss and $0.2 million of amortization of prior service cost for the SMSP.

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

	2016	2017	2018	2019	2020	2021-2025
Pension Plan	$ 30,086	$ 32,529	$ 35,156	$ 37,795	$ 40,527	$ 241,079
SMSP	4,516	4,582	4,371	4,547	4,964	25,659

As of December 31, 2015, IDACORP's and Idaho Power's minimum required contributions to the pension plan are estimated to be zero in 2016, though Idaho Power plans to contribute at least $20 million to the pension plan during 2016 in order to help balance the regulatory collection of these expenditures with the amount and timing of contributions and to mitigate the cost of being in an underfunded position.

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):

	2015	2014
Change in accumulated benefit obligation:		
Benefit obligation at January 1	$ 65,999	$ 57,341
Service cost	1,235	1,011
Interest cost	2,678	2,841
Actuarial (gain) loss	(5,008)	7,026
Benefits paid(1)	(2,511)	(2,220)
Benefit obligation at December 31	62,393	65,999
Change in plan assets:		
Fair value of plan assets at January 1	38,375	37,111
Actual return on plan assets	85	3,888
Employer contributions(1)	(383)	(404)
Benefits paid(1)	(2,511)	(2,220)
Fair value of plan assets at December 31	35,566	38,375
Funded status at end of year (included in noncurrent liabilities)	$ (26,827)	$ (27,624)

(1) Contributions and benefits paid are each net of $3,518 thousand and $3,379 thousand of plan participant contributions, and $330 thousand and $344 thousand of Medicare Part D subsidy receipts for 2015 and 2014, respectively.

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

	2015	2014
Net (gain) loss	$ (1,654)	$ 759
Prior service cost	130	145
Subtotal	(1,524)	904
Less amount recognized in regulatory assets	1,524	(904)
Net amount recognized in accumulated other comprehensive income	$ —	$ —

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

	2015	2014	2013
Service cost	$ 1,235	$ 1,011	$ 1,315
Interest cost	2,678	2,841	2,633
Expected return on plan assets	(2,680)	(2,595)	(2,328)
Amortization of net loss	—	—	98
Amortization of prior service cost	15	183	(229)
Net periodic postretirement benefit cost	$ 1,248	$ 1,440	$ 1,489

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

	2015	2014	2013
Actuarial gain (loss) during the year	$ 2,413	$ (5,733)	$ 20,673
Reclassification adjustments for:			
Amortization of net loss	—	—	98
Amortization of prior service cost	15	183	(229)
Adjustment for deferred tax effects	(949)	2,170	(8,031)
Adjustment due to the effects of regulation	(1,479)	3,380	(12,511)
Other comprehensive income related to postretirement benefit plans	$ —	$ —	$ —

In 2016, IDACORP and Idaho Power expect to recognize as components of net periodic benefit cost $26 thousand from amortizing amounts recorded in accumulated other comprehensive income as of December 31, 2015, relating to the postretirement benefit plan. The entire amount represents $26 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):

	2016	2017	2018	2019	2020	2021-2025
Expected benefit payments	$ 4,010	$ 4,050	$ 4,100	$ 4,150	$ 4,190	$ 21,030
Expected Medicare Part D subsidy receipts	380	430	470	510	560	3,480

Plan Assumptions

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

	Pension Plan		SMSP		Postretirement Benefits	
	2015	2014	2015	2014	2015	2014
Discount rate	4.60%	4.25%	4.60%	4.20%	4.60%	4.20%
Rate of compensation increase[(1)]	4.11%	4.30%	4.50%	4.50%	—	—
Medical trend rate	—	—	—	—	9.7%	6.4%
Dental trend rate	—	—	—	—	5.0%	5.0%
Measurement date	12/31/2015	12/31/2014	12/31/2015	12/31/2014	12/31/2015	12/31/2014

[(1)] The 2015 rate of compensation increase assumption for the pension plan includes an inflation component of 2.50% plus a 1.61% 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			SMSP			Postretirement Benefits		
	2015	2014	2013	2015	2014	2013	2015	2014	2013
Discount rate	4.25%	5.20%	4.20%	4.20%	5.10%	4.15%	4.20%	5.15%	4.20%
Expected long-term rate of return on assets	7.50%	7.75%	7.75%	—	—	—	7.25%	7.25%	7.25%
Rate of compensation increase	4.11%	4.30%	4.38%	4.50%	4.50%	4.50%	—	—	—
Medical trend rate	—	—	—	—	—	—	9.7%	6.4%	6.8%
Dental trend rate	—	—	—	—	—	—	5.0%	5.0%	5.0%

In October 2014, the Society of Actuaries released a new set of mortality tables referred to as RP-2014. Mortality tables are used by defined benefit plans to estimate the life expectancy of plan participants and the expected length of benefit payments in retirement. Idaho Power's measurement of its plan benefit obligations as of December 31, 2015 and 2014, and its net periodic benefit cost for 2015, reflect the adoption of the new tables, which was not material.

The assumed health care cost trend rate used to measure the expected cost of health benefits covered by the postretirement plan was 9.7 percent in 2015 and is assumed to decrease to 8.3 percent in 2016, 6.8 percent in 2017, 5.4 percent in 2018 and to gradually decrease to 4.8 percent by 2099. The assumed dental cost trend rate used to measure the expected cost of dental benefits covered by the plan was 5.0 percent, or equal to the medical trend rate if lower, for all years. A one percentage point change in the assumed health care cost trend rate would have the following effects at December 31, 2015 (in thousands of dollars):

	One-Percentage-Point	
	Increase	**Decrease**
Effect on total of cost components	$ 407	$ (297)
Effect on accumulated postretirement benefit obligation	3,719	(2,838)

Plan Assets

Pension Asset Allocation Policy: The target allocation and actual allocations at December 31, 2015 for the pension asset portfolio by asset class is set forth below:

Asset Class	**Target Allocation**	**Actual Allocation December 31, 2015**
Debt securities	24%	25%
Equity securities	54%	55%
Real estate	6%	7%
Other plan assets	16%	13%
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 16. 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, 2015				
Pension plan assets:				
Cash and cash equivalents	$ 10,519	$ —	$ —	$ 10,519
Short-term bonds	11,023	—	—	11,023
Intermediate bonds	11,499	92,742	—	104,241
Long-term bonds	—	21,747	—	21,747
Equity Securities: Large-Cap	73,489	—	—	73,489
Equity Securities: Mid-Cap	64,397	—	—	64,397
Equity Securities: Small-Cap	47,777	—	—	47,777
Equity Securities: Micro-Cap	22,186	—	—	22,186
Equity Securities: International	7,698	59,787	—	67,485
Equity Securities: Emerging Markets	9,679	23,167	—	32,846
Real estate	—	—	39,035	39,035
Private market investments	—	—	37,316	37,316
Commodities funds	—	27,555	—	27,555
Total pension assets	$ 258,267	$ 224,998	$ 76,351	$ 559,616
Postretirement plan assets[(1)]	$ 16	$ 35,550	$ —	$ 35,566
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

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

For the year ended December 31, 2015, there were no significant transfers into or out of Levels 1, 2, or 3. For the year ended December 31, 2014, there were $23.1 million of mid-cap equity security investments that were transferred from Level 2 to Level 1.

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, 2014	$ 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
Realized gains	1,897	923	2,820
Unrealized (losses) gains	(3,152)	3,193	41
Purchases	2,255	923	3,178
Sales	(802)	—	(802)
Ending balance - December 31, 2015	$ 37,316	$ 39,035	$ 76,351

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 from 2013 to 2015.

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 IDACORP's and Idaho Power's consolidated balance sheets at both December 31, 2015 and 2014 were $2.0 million.

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

The following table presents the major classifications of Idaho Power's utility plant in service, annual depreciation provisions as a percent of average depreciable balance, and accumulated provision for depreciation for the years 2015 and 2014 (in thousands of dollars):

	2015		2014	
	Balance	**Avg Rate**	**Balance**	**Avg Rate**
Production	$ 2,422,175	2.46%	$ 2,316,941	2.48%
Transmission	1,077,065	2.01%	1,016,207	2.03%
Distribution	1,578,445	2.72%	1,516,933	2.72%
General and Other	407,779	5.62%	398,131	5.49%
Total in service	5,485,464	2.68%	5,248,212	2.68%
Accumulated provision for depreciation	(1,913,927)		(1,841,011)	
In service - net	$ 3,571,537		$ 3,407,201	

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, 2015 (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	$ 641,382	$ 46,094	$ 296,671	33	771
Boardman	Boardman, OR	81,252	113	63,715	10	64
Valmy Units 1 and 2	Winnemucca, NV	402,276	1,135	184,604	50	284

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

IERCo, Idaho Power's wholly-owned subsidiary, is a joint venturer in BCC. Idaho Power's coal purchases from the joint venture were $93 million in 2015 and $79 million in each of 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 $8 million in 2015 and $9 million in each of 2014 and 2013.

IDACORP's consolidated VIE, Marysville, owns a hydroelectric plant with a net book value of approximately $19 million at December 31, 2015 and 2014.

13. ASSET RETIREMENT OBLIGATIONS (ARO)

The guidance relating to accounting for AROs requires that legal obligations associated with the retirement of property, plant, and equipment be recognized as a liability at fair value when incurred and when a reasonable estimate of the fair value of the liability can be made. Under the guidance, when a liability is initially recorded, the entity increases the carrying amount of the related long-lived asset to reflect the future retirement cost. Over time, the liability is accreted to its 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 2015, changes in estimates at its distribution facilities and at the coal-fired generation facilities resulted in a net increase of $5.0 million in the recorded AROs. The increase in the AROs in 2015 is primarily related to the impact of new coal combustion residual regulations on the Bridger 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 regulated operations of Idaho Power also collect removal costs in rates for certain assets that do not have associated AROs. Idaho Power is required to redesignate these removal costs as regulatory liabilities. See Note 3 for the removal costs recorded as regulatory liabilities on IDACORP's and Idaho Power's consolidated balance sheets as of December 31, 2015 and 2014.

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

	2015	2014
Balance at beginning of year	$ 21,930	$ 25,765
Accretion expense	993	1,061
Revisions in estimated cash flows	5,043	(4,140)
Liability settled	(1,813)	(756)
Balance at end of year	$ 26,153	$ 21,930

14. INVESTMENTS

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

	2015	2014
Idaho Power investments:		
Bridger Coal Company (equity method investment)	$ 95,159	$ 96,219
Exchange traded short-term bond funds and cash equivalents	24,459	44,942
Executive deferred compensation plan investments	102	141
Other investments	—	1
Total Idaho Power investments	119,720	141,303
Investments in affordable housing (IDACORP Financial Services)	9,909	12,762
Ida-West joint ventures (equity method investments)	11,123	11,393
Total IDACORP investments	$ 140,752	$ 165,458

Equity Method Investments

Idaho Power, through its subsidiary IERCo, is a 33 percent owner of BCC. Ida-West, through separate subsidiaries, owns 50 percent of three electric generation projects that are accounted for using the equity method: South Forks Joint Venture, Hazelton/Wilson Joint Venture, and Snow Mountain Hydro LLC. All projects are reviewed periodically for impairment. The table below presents IDACORP's and Idaho Power's earnings (loss) of unconsolidated equity-method investments (in thousands of dollars):

	2015	2014	2013
Bridger Coal Company (Idaho Power)	$ 9,773	$ 10,814	$ 10,242
Ida-West joint ventures	1,355	1,614	1,707
Other	—	(56)	(10)
Total	$ 11,128	$ 12,372	$ 11,939

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, 2015 and December 31, 2014. The following table summarizes sales of available-for-sale securities (in thousands of dollars):

	2015	2014	2013
Proceeds from sales	$ 34,243	$ —	$ 25,661
Gross realized gains from sales	—	—	11,637
Gross realized losses from sales	—	—	—

At the end of each reporting period, IDACORP and Idaho Power analyze securities in loss positions to determine whether they have experienced a decline in market value that is considered other-than-temporary. At December 31, 2015 and December 31, 2014, there were no indicators of other-than-temporary impairment related to IDACORP's and Idaho Power's investments.

Investments in Affordable Housing

IFS invests primarily in affordable housing developments, which provide a return principally by reducing federal and state income taxes through tax credits and accelerated tax depreciation benefits. IFS has focused on a diversified approach to its investment strategy in order to limit both geographic and operational risk, with most of IFS's investments having been made through syndicated funds.

15. DERIVATIVE FINANCIAL INSTRUMENTS

Commodity Price Risk

Idaho Power is exposed to market risk relating to electricity, natural gas, and other fuel commodity prices, all of which are heavily influenced by supply and demand. Market risk may 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, 2015, 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]		
		2015	2014	2013
Financial swaps	Off-system sales	$ 2,882	$ (4,119)	$ (2,637)
Financial swaps	Purchased power	748	(1,416)	947
Financial swaps	Fuel expense	(6,045)	3,862	731
Financial swaps	Other operations and maintenance	(50)	(158)	35
Forward contracts	Off-system sales	—	277	185
Forward contracts	Purchased power	(6)	(279)	(196)
Forward contracts	Fuel expense	54	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 16 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, 2015 and 2014 (in thousands of dollars):

		Asset Derivatives			Liability Derivatives		
	Balance Sheet Location	Gross Fair Value	Amounts Offset	Net Assets	Gross Fair Value	Amounts Offset	Net Liabilities
December 31, 2015							
Current:							
Financial swaps	Other current assets	$ 999	$ (785) [1]	$ 214	$ 785	$ (785)	$ —
Financial swaps	Other current liabilities	177	(177)	—	5,146	(177)	4,969
Forward contracts	Other current assets	64	—	64	—	—	—
Forward contracts	Other current liabilities	—	—	—	3	—	3
Long-term:							
Financial swaps	Other assets	148	(22)	126	22	(22)	—
Total		$ 1,388	$ (984)	$ 404	$ 5,956	$ (984)	$ 4,972
December 31, 2014							
Current:							
Financial swaps	Other current assets	$ 2,509	$ (2,002)	$ 507	$ 756	$ (756)	$ —
Financial swaps	Other current liabilities	379	(379)	—	4,335	(379) [1]	3,956
Forward contracts	Other current assets	64	—	64	—	—	—
Forward contracts	Other current liabilities	—	—	—	5	—	5
Long-term:							
Forward contracts	Other assets	63	—	63	—	—	—
Total		$ 3,015	$ (2,381)	$ 634	$ 5,096	$ (1,135)	$ 3,961

[1] Current asset and current liability derivative amounts offset include $0.9 million of collateral receivable and $1.2 million of collateral payable and for the periods ending December 31, 2015 and 2014, respectively.

The table below presents the volumes of derivative commodity forward contracts and swaps outstanding at December 31, 2015 and 2014 (in thousands of units):

		December 31,	
Commodity	Units	2015	2014
Electricity purchases	MWh	357	115
Electricity sales	MWh	120	238
Natural gas purchases	MMBtu	11,597	6,913
Natural gas sales	MMBtu	78	409
Diesel purchases	Gallons	1,068	243

Credit Risk

At December 31, 2015, 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, 2015, was $5.7 million. Idaho Power posted $0.9 million cash collateral related to this amount. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2015, Idaho Power would have been required to post an additional $9.0 million of cash collateral to its counterparties.

16. FAIR VALUE MEASUREMENTS

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

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

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

- Level 2: Financial assets and liabilities whose values are based on 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.

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

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

IDACORP’s and 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, 2015 and 2014.

The following table presents information about IDACORP's and Idaho Power's assets and liabilities measured at fair value on a recurring basis as of December 31, 2015 and 2014 (in thousands of dollars):

	December 31, 2015				December 31, 2014			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets:								
Money market funds:								
IDACORP - Parent	$ 1,000	$ —	$ —	$ 1,000	$ —	$ —	$ —	$ —
Idaho Power	10,000	—	—	10,000	100	—	—	100
Derivatives	340	64	—	404	506	128	—	634
Trading securities: Equity securities	102	—	—	102	141	—	—	141
Available-for-sale securities: ETFs	24,459	—	—	24,459	44,942	—	—	44,942
Liabilities:								
Derivatives	$ 286	$ 4,686	$ —	$ 4,972	$ 17	$ 3,944	$ —	$ 3,961

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 exchange-traded short-term bond and money market funds related to the SMSP and are held in a Rabbi Trust.

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, 2015 and 2014, using available market information and appropriate valuation methodologies (in thousands of dollars):

	December 31, 2015		December 31, 2014	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	(thousands of dollars)			
IDACORP				
Assets:				
Notes receivable[(1)]	$ 3,804	$ 3,804	$ 3,804	$ 3,804
Liabilities:				
Long-term debt[(1)]	1,726,474	1,813,243	1,615,502	1,788,197
Idaho Power				
Liabilities:				
Long-term debt[(1)]	$ 1,726,474	$ 1,813,243	$ 1,615,502	$ 1,788,197

[(1)] Notes receivable and long-term debt are categorized as Level 3 and Level 2, respectively, of the fair value hierarchy, as defined earlier in this Note 16.

Notes receivable are related to Ida-West and are valued based on unobservable inputs, including discounted cash flows, which are partially based on forecasted hydroelectric conditions. 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.

17. SEGMENT INFORMATION

IDACORP's only reportable segment is utility operations. The utility operations segment's primary source of revenue is the regulated operations of Idaho Power. Idaho Power's regulated operations include the generation, transmission, distribution, purchase, and sale of electricity. This segment also includes income from IERCo, a wholly-owned subsidiary of Idaho Power that is also subject to regulation and is a 33 percent owner of BCC, an unconsolidated joint venture.

IDACORP's other operating segments are below the quantitative and qualitative thresholds for reportable segments and are included in the "All Other" category in the table below. This category is comprised of IFS's investments in affordable housing developments and historic rehabilitation projects, Ida-West's joint venture investments in small hydroelectric generation projects, the remaining activities of IESCo, the successor to which wound down its energy marketing operations in 2003, and IDACORP's holding company expenses.

The table below summarizes the segment information for IDACORP's utility operations and the total of all other segments, and reconciles this information to total enterprise amounts (in thousands of dollars):

	Utility Operations	All Other	Eliminations	Consolidated Total
2015				
Revenues	$ 1,267,505	$ 2,784	$ —	$ 1,270,289
Operating income	282,252	(155)	—	282,097
Other income	25,868	37	—	25,905
Interest income	3,037	64	(62)	3,039
Equity-method income	9,773	1,355	—	11,128
Interest expense	81,718	278	(62)	81,934
Income before income taxes	239,211	1,024	—	240,235
Income tax expense (benefit)	48,228	(2,468)	—	45,760
Income attributable to IDACORP, Inc.	190,983	3,696	—	194,679
Total assets	5,968,835	71,704	(17,225)	6,023,314
Expenditures for long-lived assets	278,905	52	—	278,957
2014				
Revenues	$ 1,278,651	$ 3,873	$ —	$ 1,282,524
Operating income	253,437	259	—	253,696
Other income	21,517	37	—	21,554
Interest income	2,705	34	(34)	2,705
Equity-method income	10,814	1,558	—	12,372
Interest expense	79,570	265	(34)	79,801
Income before income taxes	208,903	1,623	—	210,526
Income tax expense (benefit)	19,516	(2,744)	—	16,772
Income attributable to IDACORP, Inc.	189,387	4,093	—	193,480
Total assets	5,604,506	109,044	(12,513)	5,701,037
Expenditures for long-lived assets	273,911	183	—	274,094
2013				
Revenues	$ 1,243,098	$ 3,116	$ —	$ 1,246,214
Operating income	291,691	51	—	291,742
Other income	29,288	152	—	29,440
Interest income	2,426	44	(39)	2,431
Equity-method income	10,242	1,697	—	11,939
Interest expense	80,646	425	(39)	81,032
Income before income taxes	253,001	1,519	—	254,520
Income tax expense (benefit)	76,260	(4,034)	—	72,226
Income attributable to IDACORP, Inc.	176,741	5,676	—	182,417
Total assets	5,249,228	109,541	(11,389)	5,347,380
Expenditures for long-lived assets	235,306	4	—	235,310

18. OTHER INCOME AND EXPENSE

The following table presents the components of IDACORP's Other income, net and Idaho Power's Other (expense) income, net (in thousands of dollars):

IDACORP - Other income, net	2015	2014	2013
Investment income, net	$ 2,890	$ 2,655	$ 2,373
Carrying charges on regulatory assets	1,774	1,949	2,204
Gain on sale of investments	—	—	11,637
Other income	777	588	852
Life insurance proceeds, net of premiums	1,739	1,164	18
Other expenses	(21)	(28)	(71)
Total	$ 7,159	$ 6,328	$ 17,013
Idaho Power - Other (expense) income, net			
Investment income, net	$ 2,889	$ 2,655	$ 2,369
Carrying charges on regulatory assets	1,774	1,949	2,204
Gain on sale of investments	—	—	11,637
Other income	739	551	700
SMSP expense	(9,937)	(8,339)	(8,488)
Life insurance proceeds, net of premiums	1,739	1,164	18
Other expense	(2,275)	(2,343)	(2,668)
Total	$ (5,071)	$ (4,363)	$ 5,772

19. 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, 2015, 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, 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 out of 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)
December 31, 2014			
Balance at beginning of period	$ —	$ (16,553)	$ (16,553)
Other comprehensive income before reclassifications	—	(9,333)	(9,333)
Amounts reclassified out of 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, 2015			
Balance at beginning of period	$ —	$ (24,158)	$ (24,158)
Other comprehensive income before reclassifications	—	214	214
Amounts reclassified out of AOCI	—	2,668	2,668
Net current-period other comprehensive income	—	2,882	2,882
Balance at end of period	$ —	$ (21,276)	$ (21,276)

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, 2015, 2014, and 2013 (in thousands of dollars). Items in parentheses indicate increases to net income.

	Amount Reclassified from AOCI		
	Year Ended December 31,		
	2015	2014	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	185	220	212
Net loss	4,195	2,618	2,839
Total before tax	4,380	2,838	3,051
Tax benefit[2]	(1,712)	(1,110)	(1,192)
Net of tax	2,668	1,728	1,859
Total reclassification for the period	$ 2,668	$ 1,728	$ (5,228)

(1) The realized gain is included in IDACORP's consolidated income statement in other income, net and in Idaho Power's consolidated income statements in other income (expense), net.
(2) The tax benefit is included in income tax expense (benefit) in the consolidated income statements of both IDACORP and Idaho Power.
(3) Amortization of these items is included in IDACORP's consolidated income statements in other operating expenses and in Idaho Power's consolidated income statements in other expense, net.

20. RELATED PARTY TRANSACTIONS

IDACORP: Idaho Power performs corporate functions such as financial, legal, and management services for IDACORP and its subsidiaries. Idaho Power charges IDACORP for the costs of these services based on service agreements and other specifically identified costs. For these services Idaho Power billed IDACORP $0.9 million in 2015, $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 Ida-West $8 million in 2015 and $9 million in each of 2014 and 2013.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
IDACORP, Inc.
Boise, Idaho

We have audited the accompanying consolidated balance sheets of IDACORP, Inc. and subsidiaries (the "Company") as of December 31, 2015 and 2014, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2015. Our audits also included the financial statement schedules listed in the Index at Item 8. These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedules based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of IDACORP, Inc. and subsidiaries at December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

As discussed in Note 1 to the consolidated financial statements, the Company has changed its method of presentation for deferred income taxes in 2015 due to the adoption of Accounting Standards Update (ASU) 2015-17 *Income Taxes (Topic 740)-Balance Sheet Classification of Deferred Taxes.*

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2015, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 18, 2016 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ *DELOITTE & TOUCHE LLP*

Boise, Idaho
February 18, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Idaho Power Company
Boise, Idaho

We have audited the accompanying consolidated balance sheets of Idaho Power Company and subsidiary (the "Company") as of December 31, 2015 and 2014, and the related consolidated statements of income, comprehensive income, retained earnings, and cash flows for each of the three years in the period ended December 31, 2015. Our audits also included the financial statement schedule listed in the Index at Item 8. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Idaho Power Company and subsidiary at December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Note 1 to the consolidated financial statements, the Company has changed its method of presentation for deferred income taxes in 2015 due to the adoption of Accounting Standards Update (ASU) 2015-17 *Income Taxes (Topic 740)-Balance Sheet Classification of Deferred Taxes.*

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2015, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 18, 2016 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ *DELOITTE & TOUCHE LLP*

Boise, Idaho
February 18, 2016

SUPPLEMENTAL FINANCIAL INFORMATION, UNAUDITED

QUARTERLY FINANCIAL DATA

The following unaudited information is presented for each quarter of 2015 and 2014 (in thousands of dollars, except for per share amounts). In the opinion of each company, all adjustments necessary for a fair statement of such amounts for such periods have been included. The results of operations for the interim periods are not necessarily indicative of the results to be expected for the full year. Accordingly, earnings information for any three-month period should not be considered as a basis for estimating operating results for a full fiscal year. Amounts are based upon quarterly statements and the sum of the quarters may not equal the annual amount reported.

	Quarter Ended			
	March 31	**June 30**	**September 30**	**December 31**
IDACORP, Inc.				
2015				
Revenues	$ 279,395	$ 336,328	$ 369,165	$ 285,401
Operating income	42,904	85,976	104,664	48,552
Net income	23,344	66,190	73,267	31,673
Net income attributable to IDACORP, Inc.	23,430	66,080	73,336	31,832
Basic earnings per share	$ 0.47	$ 1.32	$ 1.46	$ 0.63
Diluted earnings per share	$ 0.47	$ 1.31	$ 1.46	$ 0.63
2014				
Revenues	$ 292,719	$ 317,783	$ 382,201	$ 289,821
Operating income	48,578	71,809	105,722	27,586
Net income	27,185	44,697	87,234	34,638
Net income attributable to IDACORP, Inc.	27,404	44,540	86,889	34,648
Basic earnings per share	$ 0.55	$ 0.89	$ 1.73	$ 0.69
Diluted earnings per share	$ 0.55	$ 0.89	$ 1.73	$ 0.69
Idaho Power Company				
2015				
Revenues	$ 278,774	$ 335,321	$ 368,517	$ 284,893
Income from operations	46,159	88,836	107,614	51,833
Net income	23,462	64,340	71,727	31,455
2014				
Revenues	$ 292,320	$ 316,655	$ 380,711	$ 288,964
Income from operations	51,949	74,369	107,644	30,129
Net income	27,900	42,653	84,600	34,233

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures - IDACORP, Inc.

The Chief Executive Officer and Chief Financial Officer of IDACORP, Inc., based on their evaluation of IDACORP, Inc.'s disclosure controls and procedures (as defined in Exchange Act Rule 13a-15(e)) as of December 31, 2015, have concluded that IDACORP, Inc.'s disclosure controls and procedures are effective as of that date.

Internal Control Over Financial Reporting - IDACORP, Inc.

Management's Annual Report on Internal Control Over Financial Reporting

The management of IDACORP is responsible for establishing and maintaining adequate internal control over financial reporting for IDACORP. Internal control over financial reporting is defined in Rule 13a-15(f) promulgated under the Securities Exchange Act of 1934 as a process designed by, or under the supervision of, the company's principal executive and principal financial officers and effected by the company's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America and includes those policies and procedures that:

- pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the company;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures of the company are being made only in accordance with the authorizations of management and directors of the company; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

IDACORP's management assessed the effectiveness of the company's internal control over financial reporting as of December 31, 2015. In making this assessment, the company's management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control-Integrated Framework (2013)*.

Based on its assessment, management concluded that, as of December 31, 2015, IDACORP's internal control over financial reporting is effective based on those criteria.

IDACORP's independent registered public accounting firm has audited the financial statements included in this Annual Report on Form 10-K for the year ended December 31, 2015 and issued a report, which appears on the next page and expresses an unqualified opinion on the effectiveness of IDACORP's internal control over financial reporting as of December 31, 2015.

February 18, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
IDACORP, Inc.
Boise, Idaho

We have audited the internal control over financial reporting of IDACORP, Inc. and subsidiaries (the "Company") as of December 31, 2015, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Annual Report on Internal Control over Financial Reporting*. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2015 of the Company and our report dated February 18, 2016 expressed an unqualified opinion on those financial statements and financial statement schedules and included an explanatory paragraph regarding the Company's change in the method of presentation for deferred income taxes.

/s/ *DELOITTE & TOUCHE LLP*

Boise, Idaho
February 18, 2016

Disclosure Controls and Procedures - Idaho Power Company

The Chief Executive Officer and Chief Financial Officer of Idaho Power Company, based on their evaluation of Idaho Power Company's disclosure controls and procedures (as defined in Exchange Act Rule 13a-15(e)) as of December 31, 2015, have concluded that Idaho Power Company's disclosure controls and procedures are effective as of that date.

Internal Control Over Financial Reporting - Idaho Power Company

Management's Annual Report on Internal Control Over Financial Reporting

The management of Idaho Power Company (Idaho Power) is responsible for establishing and maintaining adequate internal control over financial reporting of Idaho Power. Internal control over financial reporting is defined in Rule 13a-15(f) promulgated under the Securities Exchange Act of 1934 as a process designed by, or under the supervision of, the company's principal executive and principal financial officers and effected by the company's board of directors, management and other personnel, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America and includes those policies and procedures that:

- pertain to the maintenance of records that in reasonable detail accurately and fairly reflect the transactions and dispositions of the assets of the company;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with accounting principles generally accepted in the United States of America, and that receipts and expenditures of the company are being made only in accordance with the authorizations of management and directors of the company; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Idaho Power's management assessed the effectiveness of the company's internal control over financial reporting as of December 31, 2015. In making this assessment, the company's management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in *Internal Control-Integrated Framework (2013)*.

Based on its assessment, management concluded that, as of December 31, 2015, Idaho Power's internal control over financial reporting is effective based on those criteria.

Idaho Power's independent registered public accounting firm has audited the financial statements included in this Annual Report on Form 10-K for the year ended December 31, 2015 and issued a report which appears on the next page and expresses an unqualified opinion on the effectiveness of Idaho Power's internal control over financial reporting as of December 31, 2015.

February 18, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Idaho Power Company
Boise, Idaho

We have audited the internal control over financial reporting of Idaho Power Company and subsidiary (the "Company") as of December 31, 2015, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Annual Report on Internal Control over Financial Reporting*. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2015 of the Company and our report dated February 18, 2016 expressed an unqualified opinion on those financial statements and financial statement schedule and included an explanatory paragraph regarding the Company's change in the method of presentation for deferred income taxes.

/s/ *DELOITTE & TOUCHE LLP*

Boise, Idaho
February 18, 2016

Changes in Internal Control Over Financial Reporting - IDACORP, Inc. and Idaho Power Company

There have been no changes in IDACORP, Inc.'s or Idaho Power Company's internal control over financial reporting during the quarter ended December 31, 2015 that have materially affected, or are reasonably likely to materially affect, IDACORP, Inc.'s or Idaho Power Company's internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS, AND CORPORATE GOVERNANCE

The portions of IDACORP's definitive proxy statement appearing under the captions "Proposal No. 1: Election of Directors," "Section 16(a) Beneficial Ownership Reporting Compliance," "Board of Directors - Committees of the Board of Directors - Audit Committee," "Corporate Governance at IDACORP - Codes of Business Conduct," and "Corporate Governance at IDACORP - Certain Relationships and Related Transactions" to be filed pursuant to Regulation 14A for the 2016 annual meeting of shareholders are hereby incorporated by reference.

Information regarding IDACORP's executive officers required by this item appears in Item 1 of this report under "Executive Officers of the Registrants."

ITEM 11. EXECUTIVE COMPENSATION

The portion of IDACORP's definitive proxy statement appearing under the caption "Executive Compensation" to be filed pursuant to Regulation 14A for the 2016 annual meeting of shareholders is hereby incorporated by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The portion of IDACORP's definitive proxy statement appearing under the caption "Security Ownership of Directors, Executive Officers, and Five-Percent Shareholders" to be filed pursuant to Regulation 14A for the 2016 annual meeting of shareholders is hereby incorporated by reference. The table below includes information as of December 31, 2015, with respect to equity compensation plans where equity securities of IDACORP may be issued. These plans are the 1994 Restricted Stock Plan (RSP) and the IDACORP 2000 Long-Term Incentive and Compensation Plan (LTICP).

Equity Compensation Plan Information

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted-average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by shareholders[1]	—	$ —	1,059,338 [2]
Equity compensation plans not approved by shareholders	—	$ —	—
Total	—	$ —	1,059,338

[1] Consists of the RSP and the LTICP.

[2] 1,043,542 shares under the LTICP may be issued in connection with stock options, stock appreciation rights, restricted stock, restricted stock units, performance units, performance shares, or other equity-based awards as of December 31, 2015. 15,796 shares remain available for future issuance under the RSP and may be issued as restricted stock or performance-based restricted stock. The number of shares listed in this column excludes (i) issued but unvested performance-based restricted shares, and (ii) issued but unvested time-based restricted shares, in both cases issued pursuant to the LTICP and unvested as of December 31, 2015.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The portions of IDACORP's definitive proxy statement appearing under the captions "Certain Relationships and Related Transactions" and "Corporate Governance at IDACORP – Director Independence and Executive Sessions" to be filed pursuant to Regulation 14A for the 2016 annual meeting of shareholders are hereby incorporated by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

IDACORP: The portion of IDACORP's definitive proxy statement appearing under the caption "Independent Accountant Billings" in the proxy statement to be filed pursuant to Regulation 14A for the 2016 annual meeting of shareholders is hereby incorporated by reference.

Idaho Power: The table below presents the aggregate fees our principal independent registered public accounting firm, Deloitte & Touche LLP, billed or is expected to bill to Idaho Power for the fiscal years ended December 31, 2015 and 2014:

	2015	2014
Audit fees	$ 1,280,500	$ 1,239,913
Audit-related fees(1)	6,732	32,300
Tax fees(2)	37,655	1,640
All other fees(3)	2,000	2,000
Total	$ 1,326,887	$ 1,275,853

(1) Audits of Idaho Power's benefit plans and compliance audit for the U.S. Department of Energy Smart Grid Investment Grant Program.

(2) Includes fees for benefit plan tax returns and consultation related to tax planning.

(3) Accounting research tool subscription.

Policy on Audit Committee Pre-Approval:

Idaho Power and the Audit Committee are committed to ensuring the independence of the independent registered public accounting firm, both in fact and in appearance. In this regard, the Audit Committee has established and periodically reviews a pre-approval policy for audit and non-audit services. For 2014 and 2015, all audit and non-audit services and all fees paid in connection with those services were pre-approved by the Audit Committee.

In addition to the audits of Idaho Power's consolidated financial statements, the independent public accounting firm may be engaged to provide certain audit-related, tax, and other services. The Audit Committee must pre-approve all services performed by the independent public accounting firm to assure that the provision of those services does not impair the public accounting firm's independence. The services that the Audit Committee will consider include: audit services such as attest services, changes in the scope of the audit of the financial statements, and the issuance of comfort letters and consents in connection with financings; audit-related services such as internal control reviews and assistance with internal control reporting requirements; attest services related to financial reporting that are not required by statute or regulation, and accounting consultations and audits related to proposed transactions and new or proposed accounting rules, standards and interpretations; and tax compliance and planning services. Unless a type of service to be provided by the independent public accounting firm has received general pre-approval, it will require specific pre-approval by the Audit Committee. In addition, any proposed services exceeding pre-approved cost levels will require specific pre-approval by the Audit Committee. Under the pre-approval policy, the Audit Committee has delegated to the Chairman of the Audit Committee pre-approval authority for proposed services; however, the Chairman must report any pre-approval decisions to the Audit Committee at its next scheduled meeting.

Any request to engage the independent public accounting firm to provide a service which has not received general pre-approval must be submitted as a written proposal to Idaho Power's Chief Financial Officer with a copy to the General Counsel. The request must include a detailed description of the service to be provided, the proposed fee, and the business reasons for engaging the independent public accounting firm to provide the service. Upon approval by the Chief Financial Officer, the General Counsel, and the independent public accounting firm that the proposed engagement complies with the terms of the pre-approval policy and the applicable rules and regulations, the request will be presented to the Audit Committee or the Committee Chairman, as the case may be, for pre-approval.

In determining whether to pre-approve the engagement of the independent public accounting firm, the Audit Committee or the Committee Chairman, as the case may be, must consider, among other things, the pre-approval policy, applicable rules and regulations, and whether the nature of the engagement and the related fees are consistent with the following principles:

- the independent public accounting firm cannot function in the role of management of Idaho Power; and
- the independent public accounting firm cannot audit its own work.

The pre-approval policy and separate supplements to the pre-approval policy describe the specific audit, audit related, tax, and other services that have the general pre-approval of the Audit Committee. The term of any pre-approval is 12 months from the date of pre-approval, unless the Audit Committee specifically provides for a different period. The Audit Committee will periodically revise the list of pre-approved services, based on subsequent determinations.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(1) and (2) Please refer to Part II, Item 8 - "Financial Statements and Supplementary Data" for a complete listing of consolidated financial statements and financial statement schedules.

(3) Exhibits. ***Note Regarding Reliance on Statements in Agreements***: The agreements filed as exhibits to this Annual Report on Form 10-K are filed to provide information regarding their terms and are not intended to provide any other factual or disclosure information about IDACORP, Inc., Idaho Power Company, or the other parties to the agreements. Some of the agreements contain statements, representations, and warranties by each of the parties to the applicable agreement. These representations and warranties have been made solely for the benefit of the other parties to the applicable agreement and (a) should not in all instances be treated as categorical statements of fact, but rather as a way of allocating the risk to one of the parties to the agreement if those statements prove to be inaccurate; (b) have been qualified by disclosures that were made to the other party, which disclosures are not necessarily reflected in the agreement; (c) may apply standards of materiality in a way that is different from what may be viewed as material to investors; and (d) were made only as of the date of the applicable agreement or such other date or dates as may be specified in the agreement and are subject to more recent developments. Accordingly, readers should not rely upon the statements, representations, or warranties made in the agreements.

		Incorporated by Reference				
Exhibit No.	**Exhibit Description**	**Form**	**File No.**	**Exhibit No.**	**Date**	**Included Herewith**
2	Agreement and Plan of Exchange between IDACORP, Inc. and Idaho Power Company, dated as of February 2, 1998	S-4	333-48031	A	3/16/1998	
3.1	Restated Articles of Incorporation of Idaho Power Company as filed with the Secretary of State of Idaho on June 30, 1989	S-3 Post-Effective Amend. No. 2	33-00440	4(a)(xiii)	6/30/1989	
3.2	Statement of Resolution Establishing Terms of Flexible Auction Series A, Serial Preferred Stock, Without Par Value (cumulative stated value of $100,000 per share) of Idaho Power Company, as filed with the Secretary of State of Idaho on November 5, 1991	S-3	33-65720	4(a)(ii)	7/7/1993	
3.3	Statement of Resolution Establishing Terms of 7.07% Serial Preferred Stock, Without Par Value (cumulative stated value of $100 per share) of Idaho Power Company, as filed with the Secretary of State of Idaho on June 30, 1993	S-3	33-65720	4(a)(iii)	7/7/1993	
3.4	Articles of Share Exchange, as filed with the Secretary of State of Idaho on September 29, 1998	S-8 Post-Effective Amend. No. 1	33-56071-9 9	3(d)	10/1/1998	
3.5	Articles of Amendment to Restated Articles of Incorporation of Idaho Power Company, as filed with the Secretary of State of Idaho on June 15, 2000	10-Q	1-3198	3(a)(iii)	8/4/2000	
3.6	Articles of Amendment to Restated Articles of Incorporation of Idaho Power Company, as filed with the Secretary of State of Idaho on January 21, 2005	8-K	1-3198	3.3	1/26/2005	
3.7	Articles of Amendment to Restated Articles of Incorporation of Idaho Power Company, as amended, as filed with the Secretary of State of Idaho on November 19, 2007	8-K	1-3198	3.3	11/19/2007	

Exhibit No.	Exhibit Description	Incorporated by Reference Form	File No.	Exhibit No.	Date	Included Herewith
3.8	Articles of Amendment to Restated Articles of Incorporation of Idaho Power Company, as amended, as filed with the Secretary of State of Idaho on May 18, 2012	8-K	1-3198	3.14	5/21/2012	
3.9	Amended Bylaws of Idaho Power Company, amended on November 15, 2007 and presently in effect	8-K	1-3198	3.2	11/19/2007	
3.10	Articles of Incorporation of IDACORP, Inc.	S-3	333-64737	3.1	11/4/1998	
3.11	Articles of Amendment to Articles of Incorporation of IDACORP, Inc. as filed with the Secretary of State of Idaho on March 9, 1998	S-3 Amend. No. 1	333-64737	3.2	11/4/1998	
3.12	Articles of Amendment to Articles of Incorporation of IDACORP, Inc. creating A Series Preferred Stock, without par value, as filed with the Secretary of State of Idaho on September 17, 1998	S-3 Post-Effective Amend. No. 1	333-00139-99	3(b)	9/22/1998	
3.13	Articles of Amendment to Articles of Incorporation of IDACORP, Inc., as amended, as filed with the Secretary of State of Idaho on May 18, 2012	8-K	1-14465	3.13	5/21/2012	
3.14	Amended and Restated Bylaws of IDACORP, Inc., amended on October 29, 2014 and presently in effect	10-Q	1-14465	3.15	10/30/2014	
4.1	Mortgage and Deed of Trust, dated as of October 1, 1937, between Idaho Power Company and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company) and R. G. Page, as Trustees		2-3413	B-2		
4.2	Idaho Power Company Supplemental Indentures to Mortgage and Deed of Trust:					
	File number 1-MD, as Exhibit B-2-a, First, July 1, 1939					
	File number 2-5395, as Exhibit 7-a-3, Second, November 15, 1943					
	File number 2-7237, as Exhibit 7-a-4, Third, February 1, 1947					
	File number 2-7502, as Exhibit 7-a-5, Fourth, May 1, 1948					
	File number 2-8398, as Exhibit 7-a-6, Fifth, November 1, 1949					
	File number 2-8973, as Exhibit 7-a-7, Sixth, October 1, 1951					
	File number 2-12941, as Exhibit 2-C-8, Seventh, January 1, 1957					
	File number 2-13688, as Exhibit 4-J, Eighth, July 15, 1957					
	File number 2-13689, as Exhibit 4-K, Ninth, November 15, 1957					
	File number 2-14245, as Exhibit 4-L, Tenth, April 1, 1958					
	File number 2-14366, as Exhibit 2-L, Eleventh, October 15, 1958					
	File number 2-14935, as Exhibit 4-N, Twelfth, May 15, 1959					
	File number 2-18976, as Exhibit 4-O, Thirteenth, November 15, 1960					
	File number 2-18977, as Exhibit 4-Q, Fourteenth, November 1, 1961					
	File number 2-22988, as Exhibit 4-B-16, Fifteenth, September 15, 1964					
	File number 2-24578, as Exhibit 4-B-17, Sixteenth, April 1, 1966					
	File number 2-25479, as Exhibit 4-B-18, Seventeenth, October 1, 1966					
	File number 2-45260, as Exhibit 2(c), Eighteenth, September 1, 1972					
	File number 2-49854, as Exhibit 2(c), Nineteenth, January 15, 1974					
	File number 2-51722, as Exhibit 2(c)(i), Twentieth, August 1, 1974					
	File number 2-51722, as Exhibit 2(c)(ii), Twenty-first, October 15, 1974					
	File number 2-57374, as Exhibit 2(c), Twenty-second, November 15, 1976					
	File number 2-62035, as Exhibit 2(c), Twenty-third, August 15, 1978					
	File number 33-34222, as Exhibit 4(d)(iii), Twenty-fourth, September 1, 1979					
	File number 33-34222, as Exhibit 4(d)(iv), Twenty-fifth, November 1, 1981					
	File number 33-34222, as Exhibit 4(d)(v), Twenty-sixth, May 1, 1982					
	File number 33-34222, as Exhibit 4(d)(vi), Twenty-seventh, May 1, 1986					
	File number 33-00440, as Exhibit 4(c)(iv), Twenty-eighth, June 30, 1989					
	File number 33-34222, as Exhibit 4(d)(vii), Twenty-ninth, January 1, 1990					
	File number 33-65720, as Exhibit 4(d)(iii), Thirtieth, January 1, 1991					
	File number 33-65720, as Exhibit 4(d)(iv), Thirty-first, August 15, 1991					

Exhibit No.	Exhibit Description	Incorporated by Reference Form	File No.	Exhibit No.	Date	Included Herewith
	File number 33-65720, as Exhibit 4(d)(v), Thirty-second, March 15, 1992					
	File number 33-65720, as Exhibit 4(d)(vi), Thirty-third, April 1, 1993					
	File number 1-3198, Form 8-K, filed on 12/20/93, as Exhibit 4, Thirty-fourth, December 1, 1993					
	File number 1-3198, Form 8-K, filed on 11/21/00, as Exhibit 4, Thirty-fifth, November 1, 2000					
	File number 1-3198, Form 8-K, filed on 10/1/01, as Exhibit 4, Thirty-sixth, October 1, 2001					
	File number 1-3198, Form 8-K, filed on 4/16/03, as Exhibit 4, Thirty-seventh, April 1, 2003					
	File number 1-3198, Form 10-Q for the quarter ended June 30, 2003, filed on 8/7/03, as Exhibit 4(a)(iii), Thirty-eighth, May 15, 2003					
	File number 1-3198, Form 10-Q for the quarter ended September 30, 2003, filed on 11/6/03, as Exhibit 4(a)(iv), Thirty-ninth, October 1, 2003					
	File number 1-3198, Form 8-K filed on 5/10/05, as Exhibit 4, Fortieth, May 1, 2005					
	File number 1-3198, Form 8-K filed on 10/10/06, as Exhibit 4, Forty-first, October 1, 2006					
	File number 1-3198, Form 8-K filed on 6/4/07, as Exhibit 4, Forty-second, May 1, 2007					
	File number 1-3198, Form 8-K filed on 9/26/07, as Exhibit 4, Forty-third, September 1, 2007					
	File number 1-3198, Form 8-K filed on 4/3/08, as Exhibit 4, Forty-fourth, April 1, 2008					
	File number 1-3198, Form 10-K filed on 2/23/10, as Exhibit 4.10, Forty-fifth, February 1, 2010					
	File number 1-3198, Form 8-K filed on 6/18/10, as Exhibit 4, Forty-sixth, June 1, 2010					
	File number 1-3198, Form 8-K filed on 7/12/2013, as Exhibit 4.1, Forty-seventh, July 1, 2013					
4.3	Instruments relating to Idaho Power Company American Falls bond guarantee (see Exhibit 10.23)	10-Q	1-3198	4(b)	8/4/2000	
4.4	Agreement of Idaho Power Company to furnish certain debt instruments	S-3	33-65720	4(f)	7/7/1993	
4.5	Agreement of IDACORP, Inc. to furnish certain debt instruments	10-Q	1-14465	4(c)(ii)	11/6/2003	
4.6	Agreement and Plan of Merger dated March 10, 1989, between Idaho Power Company, a Maine corporation, and Idaho Power Migrating Corporation	S-3 Post-Effective Amend. No. 2	33-00440	2(a)(iii)	6/30/1989	
4.7	Indenture for Senior Debt Securities dated as of February 1, 2001, between IDACORP, Inc. and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), as trustee	8-K	1-14465	4.1	2/28/2001	
4.8	First Supplemental Indenture dated as of February 1, 2001 to Indenture for Senior Debt Securities dated as of February 1, 2001 between IDACORP, Inc. and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), as trustee	8-K	1-14465	4.2	2/28/2001	
4.9	Indenture for Debt Securities dated as of August 1, 2001 between Idaho Power Company and Deutsche Bank Trust Company Americas (formerly known as Bankers Trust Company), as trustee	S-3	333-67748	4.13	8/16/2001	
4.10	Idaho Power Company Instrument of Further Assurance relating to Mortgage and Deed of Trust, dated as of August 3, 2010	10-Q	1-3198	4.12	8/5/2010	
10.1	Agreement, dated as of October 11, 1973, between Idaho Power Company and Pacific Power & Light Company		2-49584	5(c)		
10.2	Amended and Restated Agreement for the Operation of the Jim Bridger Project, dated December 11, 2014, between Idaho Power Company and PacifiCorp	10-K	1-14465, 1-3198	10.4	2/19/2015	
10.3	Amended and Restated Agreement for the Ownership of the Jim Bridger Project, dated December 11, 2014, between Idaho Power Company and PacifiCorp	10-K	1-14465, 1-3198	10.5	2/19/2015	
10.4	Joint Ownership and Operating Agreement, dated October 24, 2014, between Idaho Power Company and PacifiCorp	8-K	1-14465, 1-3198	10.1	10/24/2014	
10.5	Letter Agreement, dated January 23, 1976, between Idaho Power Company and Portland General Electric Company		2-56513	5(i)		

Exhibit No.	Exhibit Description	Incorporated by Reference Form	File No.	Exhibit No.	Date	Included Herewith
10.6	Agreement for Construction, Ownership and Operation of the Number One Boardman Station on Carty Reservoir, dated as of October 15, 1976, between Portland General Electric Company and Idaho Power Company	S-7	2-62034	5(s)	6/30/1978	
10.7	Amendment, dated September 30, 1977, relating to the agreement filed as Exhibit 10.5	S-7	2-62034	5(t)	6/30/1978	
10.8	Amendment, dated October 31, 1977, relating to the agreement filed as Exhibit 10.5	S-7	2-62034	5(u)	6/30/1978	
10.9	Amendment, dated January 23, 1978, relating to the agreement filed as Exhibit 10.5	S-7	2-62034	5(v)	6/30/1978	
10.10	Amendment, dated February 15, 1978, relating to the agreement filed as Exhibit 10.5	S-7	2-62034	5(w)	6/30/1978	
10.11	Amendment, dated September 1, 1979, relating to the agreement filed as Exhibit 10.5	S-7	2-68574	5(x)	7/23/1980	
10.12	Participation Agreement, dated September 1, 1979, relating to the sale and leaseback of coal handling facilities at the Number One Boardman Station on Carty Reservoir	S-7	2-68574	5(z)	7/23/1980	
10.13	Agreements for the Operation, Construction and Ownership of the North Valmy Power Plant Project, dated December 12, 1978, between Sierra Pacific Power Company and Idaho Power Company	S-7	2-64910	5(y)	6/29/1979	
10.14	Framework Agreement, dated October 1, 1984, between the State of Idaho and Idaho Power Company relating to Idaho Power Company's Swan Falls and Snake River water rights	S-3	33-65720	10(h)	7/7/1993	
10.15	Agreement, dated October 25, 1984, between the State of Idaho and Idaho Power Company, relating to the agreement filed as Exhibit 10.14	S-3	33-65720	10(h)(i)	7/7/1993	
10.16	Contract to Implement, dated October 25, 1984, between the State of Idaho and Idaho Power Company, relating to the agreement filed as Exhibit 10.14	S-3	33-65720	10(h)(ii)	7/7/1993	
10.17	Settlement Agreement, dated March 25, 2009, between the State of Idaho and Idaho Power Company relating to the agreement filed as Exhibit 10.14	10-Q	1-14465	10.58	5/7/2009	
10.18	Agreement Regarding the Ownership, Construction, Operation and Maintenance of the Milner Hydroelectric Project (FERC No. 2899), dated January 22, 1990, between Idaho Power Company and the Twin Falls Canal Company and the Northside Canal Company Limited	S-3	33-65720	10(m)	7/7/1993	
10.19	Credit Agreement, dated November 6, 2015, among IDACORP, Inc., Wells Fargo Bank, National Association, as administrative agent, swingline lender, and LC issuer, JPMorgan Chase Bank, N.A., as syndication agent and LC issuer, KeyBank National Association and MUFG Union Bank, N.A., as documentation agents and LC Issuers, and Wells Fargo Securities, LLC, J.P. Morgan Securities LLC, Keybanc Capital Markets Inc., and MUFG Union Bank, N.A. as joint lead arrangers and joint book runners, and the other lenders named therein	8-K	1-14465, 1-3198	10.1	11/9/2015	
10.20	Credit Agreement, dated November 6, 2015, among Idaho Power Company, Wells Fargo Bank, National Association, as administrative agent, swingline lender, and LC issuer, JPMorgan Chase Bank, N.A., as syndication agent and LC issuer, KeyBank National Association and MUFG Union Bank, N.A., as documentation agents and LC Issuers, and Wells Fargo Securities, LLC, J.P. Morgan Securities LLC, Keybanc Capital Markets, Inc., and MUFG Union Bank, N.A. as joint lead arrangers and joint book runners, and the other lenders named therein	8-K	1-14465, 1-3198	10.2	11/9/2015	
10.21	Loan Agreement, dated October 1, 2006, between Sweetwater County, Wyoming and Idaho Power Company	8-K	1-3198	10.1	10/10/2006	
10.22	Guaranty Agreement, dated February 10, 1992, between Idaho Power Company and New York Life Insurance Company, as Note Purchaser, relating to $11,700,000 Guaranteed Notes due 2017 of Milner Dam Inc.	S-3	33-65720	10(m)(i)	7/7/1993	

Exhibit No.	Exhibit Description	Incorporated by Reference Form	File No.	Exhibit No.	Date	Included Herewith
10.23	Guaranty Agreement, dated April 11, 2000, between Idaho Power Company and Bank One Trust Company, N.A., as Trustee, relating to $19,885,000 American Falls Replacement Dam Refinancing Bonds of the American Falls Reservoir District, Idaho	10-Q	1-3198	10(c)	8/4/2000	
10.24	Guaranty Agreement, dated as of August 30, 1974, between Idaho Power Company and Pacific Power & Light Company	S-7	2-62034	5(r)	6/30/1978	
10.25[1]	Idaho Power Company Security Plan for Senior Management Employees I, amended and restated effective December 31, 2004, and as further amended November 20, 2008	10-K	1-14465, 1-3198	10.15	2/26/2009	
10.26[1]	Amendment, dated September 19, 2012, to the Idaho Power Company Security Plan for Senior Management Employees I	10-Q	1-14465, 1-3198	10.62	11/1/2012	
10.27[1]	Idaho Power Company Security Plan for Senior Management Employees II, effective January 1, 2005, as amended and restated November 30, 2011	10-K	1-14465, 1-3198	10.21	2/22/2012	
10.28[1]	Amendment, dated September 19, 2012, to the Idaho Power Company Security Plan for Senior Management Employees II	10-Q	1-14465, 1-3198	10.63	11/1/2012	
10.29[1]	Amendment, dated January 16, 2014, to the Idaho Power Company Security Plan for Senior Management Employees II	10-K	1-14465, 1-3198	10.26	2/20/2014	
10.30[1]	IDACORP, Inc. Restricted Stock Plan, as amended and restated September 20, 2007	10-Q	1-14465, 1-3198	10(h)(iii)	10/31/2007	
10.31[1]	IDACORP, Inc. Restricted Stock Plan - Form of Restricted Stock Agreement (Time-Vesting)	10-Q	1-14465, 1-3198	10(h)(vi)	11/2/2006	
10.32[1]	IDACORP, Inc. Restricted Stock Plan - Form of Performance Stock Agreement (Performance Vesting)	10-Q	1-14465, 1-3198	10(h) (vii)	11/2/2006	
10.33[1]	Idaho Power Company Security Plan for Board of Directors - a non-qualified deferred compensation plan, as amended and restated effective July 20, 2006	10-Q	1-14465, 1-3198	10(h) (viii)	11/2/2006	
10.34[1]	IDACORP, Inc. Non-Employee Directors Stock Compensation Plan, as amended November 19, 2015					X
10.35[1]	Form of Officer Indemnification Agreement between IDACORP, Inc. and Officers of IDACORP, Inc. and Idaho Power Company, as amended July 20, 2006	10-Q	1-14465, 1-3198	10(h) (xix)	11/2/2006	
10.36[1]	Form of Director Indemnification Agreement between IDACORP, Inc. and Directors of IDACORP, Inc., as amended July 20, 2006	10-Q	1-14465, 1-3198	10(h) (xx)	11/2/2006	
10.37[1]	Form of Amended and Restated Change in Control Agreement between IDACORP, Inc. and Officers of IDACORP and Idaho Power Company (senior vice president and higher), approved November 20, 2008	10-K	1-14465, 1-3198	10.24	2/26/2009	
10.38[1]	Form of Amended and Restated Change in Control Agreement between IDACORP, Inc. and Officers of IDACORP and Idaho Power Company (below senior vice president), approved November 20, 2008	10-K	1-14465, 1-3198	10.25	2/26/2009	
10.39[1]	Form of Amended and Restated Change in Control Agreement between IDACORP, Inc. and Officers of IDACORP, Inc. and Idaho Power Company, approved March 17, 2010	8-K	1-14465, 1-3198	10.1	3/24/2010	
10.40[1]	IDACORP, Inc. and/or Idaho Power Company Executive Officers with Amended and Restated Change in Control Agreements chart, as of February 12, 2016					X
10.41[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan, as amended November 18, 2010	10-K	1-14465, 1-3198	10.33	2/23/2011	
10.42[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Restricted Stock Award Agreement (Time Vesting)	10-K	1-14465, 1-3198	10.43	2/19/2015	
10.43[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Performance Share Award Agreement (Performance with Two Goals)	10-K	1-14465, 1-3198	10.44	2/19/2015	
10.44[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Restricted Stock Award Agreement (Time Vesting) (For 2014 and Prior Outstanding Awards)	10-Q	1-14465, 1-3198	10(h) (xvii)	11/2/2006	

Exhibit No.	Exhibit Description	Incorporated by Reference Form	File No.	Exhibit No.	Date	Included Herewith
10.45[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Performance Share Award Agreement (Performance with Two Goals) (For 2014 and Prior Outstanding Awards)	10-Q	1-14465, 1-3198	10.69	5/5/2011	
10.46[1]	IDACORP, Inc. Executive Incentive Plan, as amended and restated January 16, 2014 (superseded by Exhibit 10.47 effective February 10, 2016)	10-K	1-14465, 1-3198	10.42	2/20/2014	
10.47[1]	IDACORP, Inc. Executive Incentive Plan, as amended and restated February 11, 2016					X
10.48[1]	Idaho Power Company Executive Deferred Compensation Plan, effective November 15, 2000, as amended November 20, 2008	10-K	1-14465, 1-3198	10.32	2/26/2009	
10.49[1]	IDACORP, Inc. and Idaho Power Company Compensation for Non-Employee Directors of the Board of Directors, effective January 1, 2015 (superseded by Exhibit 10.50 effective January 1, 2016)	10-K	1-14465, 1-3198	10.49	2/19/2015	
10.50[1]	IDACORP, Inc. and Idaho Power Company Compensation for Non-Employee Directors of the Board of Directors, effective January 1, 2016					X
10.51[1]	Form of IDACORP, Inc. Director Deferred Compensation Agreement, as amended November 20, 2008	10-K	1-14465, 1-3198	10.46	2/26/2009	
10.52[1]	Form of Letter Agreement to Amend Outstanding IDACORP, Inc. Director Deferred Compensation Agreement (November 16, 2008)	10-K	1-14465, 1-3198	10.47	2/26/2009	
10.53[1]	Form of Amendment to IDACORP, Inc. Director Deferred Compensation Agreement, as amended November 20, 2008	10-K	1-14465, 1-3198	10.48	2/26/2009	
10.54[1]	Form of Termination of IDACORP, Inc. Director Deferred Compensation Agreement, as amended November 20, 2008	10-K	1-14465, 1-3198	10.49	2/26/2009	
10.55[1]	Form of Idaho Power Company Director Deferred Compensation Agreement, as amended November 20, 2008	10-K	1-14465, 1-3198	10.50	2/26/2009	
10.56[1]	Form of Letter Agreement to Amend Outstanding Idaho Power Company Director Deferred Compensation Agreement (November 16, 2008)	10-K	1-14465, 1-3198	10.51	2/26/2009	
10.57[1]	Form of Amendment to Idaho Power Company Director Deferred Compensation Agreement, as amended November 20, 2008	10-K	1-14465, 1-3198	10.52	2/26/2009	
10.58[1]	Form of Termination of Idaho Power Company Director Deferred Compensation Agreement, as amended November 20, 2008	10-K	1-14465, 1-3198	10.53	2/26/2009	
10.59[1]	Idaho Power Company Restated Employee Savings Plan, as restated as of January 1, 2016					X
12.1	IDACORP, Inc. Computation of Ratio of Earnings to Fixed Charges and Supplemental Ratio of Earnings to Fixed Charges					X
12.2	Idaho Power Company Computation of Ratio of Earnings to Fixed Charges and Supplemental Ratio of Earnings to Fixed Charges					X
21.1	Subsidiaries of IDACORP, Inc.	10-K	1-14465, 1-3198	21.1	2/21/2013	
23.1	Consent of Registered Independent Accounting Firm					X
23.2	Consent of Registered Independent Accounting Firm					X
31.1	IDACORP, Inc. Rule 13a-14(a) CEO certification					X
31.2	IDACORP, Inc. Rule 13a-14(a) CFO certification					X
31.3	Idaho Power Rule 13a-14(a) CEO certification					X
31.4	Idaho Power Rule 13a-14(a) CFO certification					X
32.1	IDACORP, Inc. Section 1350 CEO certification					X
32.2	IDACORP, Inc. Section 1350 CFO certification					X
32.3	Idaho Power Section 1350 CEO certification					X
32.4	Idaho Power Section 1350 CFO certification					X
95.1	Mine Safety Disclosures					X

Exhibit No.	Exhibit Description	Incorporated by Reference Form	File No.	Exhibit No.	Date	Included Herewith
101.INS	XBRL Instance Document					X
101.SCH	XBRL Taxonomy Extension Schema Document					X
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document					X
101.LAB	XBRL Taxonomy Extension Label Linkbase Document					X
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document					X
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document					X

[1] Management contract or compensatory plan or arrangement

IDACORP, INC.
SCHEDULE I - CONDENSED FINANCIAL INFORMATION OF REGISTRANT

CONDENSED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31,		
	2015	**2014**	**2013**
	(thousands of dollars)		
Income:			
Equity in income of subsidiaries	$ 194,426	$ 193,707	$ 182,463
Investment income	1	—	3
Total income	194,427	193,707	182,466
Expenses:			
Operating expenses	831	1,376	940
Interest expense	276	261	416
Other expenses	45	45	71
Total expenses	1,152	1,682	1,427
Income from Before Income Taxes	193,275	192,025	181,039
Income Tax Benefit	(1,404)	(1,455)	(1,378)
Net Income Attributable to IDACORP, Inc.	194,679	193,480	182,417
Other comprehensive (income) loss	2,882	(7,605)	563
Comprehensive Income Attributable to IDACORP, Inc.	$ 197,561	$ 185,875	$ 182,980

The accompanying note is an integral part of these statements.

IDACORP, INC.
CONDENSED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2015	**2014**	**2013**
	(thousands of dollars)		
Operating Activities:			
Net cash provided by operating activities	$ 100,465	$ 109,289	$ 96,391
Investing Activities:			
Distributions from (contributions to) subsidiaries	—	—	2,282
Net cash provided by (used in) investing activities	—	—	2,282
Financing Activities:			
Issuance of common stock	—	195	255
Dividends on common stock	(96,810)	(88,489)	(78,832)
(Decrease) increase in short-term borrowings	(11,300)	(23,450)	(14,950)
Change in intercompany notes payable	5,572	(198)	647
Other	(1,675)	(469)	(431)
Net cash used in financing activities	(104,213)	(112,411)	(93,311)
Net (decrease) increase in cash and cash equivalents	(3,748)	(3,122)	5,362
Cash and cash equivalents at beginning of year	5,776	8,898	3,536
Cash and cash equivalents at end of year	$ 2,028	$ 5,776	$ 8,898

The accompanying note is an integral part of these statements.

IDACORP, INC.
CONDENSED BALANCE SHEETS

	December 31,			
	2015		2014	
Assets	(thousands of dollars)			
Current Assets:				
Cash and cash equivalents	$	2,028	$	5,776
Receivables		946		1,702
Income taxes receivable		7,241		—
Deferred income taxes		—		42,766
Other		119		106
Total current assets		10,334		50,350
Investment in subsidiaries		2,007,984		1,910,084
Other Assets:				
Deferred income taxes		76,410		44,546
Other		402		287
Total other assets		76,812		44,833
Total assets	$	2,095,130	$	2,005,267
Liabilities and Shareholders' Equity				
Current Liabilities:				
Notes payable	$	20,000	$	31,300
Accounts payable		13		8
Taxes accrued		—		8,950
Other		765		854
Total current liabilities		20,778		41,112
Other Liabilities:				
Intercompany notes payable		15,292		9,658
Other		1,175		1,296
Total other liabilities		16,467		10,954
IDACORP, Inc. Shareholders' Equity		2,057,885		1,953,201
Total Liabilities and Shareholders' Equity	$	2,095,130	$	2,005,267

The accompanying note is an integral part of these statements.

NOTE TO CONDENSED FINANCIAL STATEMENTS

1. BASIS OF PRESENTATION

Pursuant to rules and regulations of the Securities and Exchange Commission, the unconsolidated condensed financial statements of IDACORP, Inc. do not reflect all of the information and notes normally included with financial statements prepared in accordance with accounting principles generally accepted in the United States of America. Therefore, these financial statements should be read in conjunction with the consolidated financial statements and related notes included in the 2015 Form 10-K, Part II, Item 8.

Accounting for Subsidiaries: IDACORP has accounted for the earnings of its subsidiaries under the equity method of accounting in these unconsolidated condensed financial statements. Included in net cash provided by operating activities in the condensed statements of cash flows are dividends that IDACORP subsidiaries paid to IDACORP of $99 million in 2015 and $91 million in 2014 and 2013.

IDACORP, INC.
SCHEDULE II - CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
Years Ended December 31, 2015, 2014, and 2013

Column A	Column B	Column C		Column D	Column E
		Additions			
Classification	Balance at Beginning of Year	Charged to Income	Charged (Credited) to Other Accounts	Deductions[1]	Balance at End of Year
		(thousands of dollars)			
2015:					
Reserves deducted from applicable assets					
Reserve for uncollectible accounts	$ 2,104	$ 3,327	$ 819	$ 4,895	$ 1,355
Reserve for uncollectible notes	552	—	—	—	552
Other Reserves:					
Injuries and damages	1,995	890	—	1,011	1,874
2014:					
Reserves deducted from applicable assets					
Reserve for uncollectible accounts	$ 2,502	$ 6,756	$ 198	$ 7,352	$ 2,104
Reserve for uncollectible notes	885	(333)	—	—	552
Other Reserves:					
Rate refunds	398	(398)	—	—	—
Injuries and damages	1,671	461	—	137	1,995
2013:					
Reserves deducted from applicable assets					
Reserve for uncollectible accounts	$ 1,873	$ 5,777	$ (38)	$ 5,110	$ 2,502
Reserve for uncollectible notes	1,260	(375)	—	—	885
Other Reserves:					
Rate refunds	—	398	—	—	398
Injuries and damages	5,480	913	—	4,722	1,671

[1] Represents deductions from the reserves for purposes for which the reserves were created. In the case of uncollectible accounts, and notes reserves, includes reversals of amounts previously written off.

IDAHO POWER COMPANY
SCHEDULE II - CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
Years Ended December 31, 2015, 2014, and 2013

Column A	Column B	Column C		Column D	Column E
		Additions			
Classification	Balance at Beginning of Year	Charged to Income	Charged (Credited) to Other Accounts	Deductions[1]	Balance at End of Year
	(thousands of dollars)				
2015:					
Reserves deducted from applicable assets					
Reserve for uncollectible accounts	$ 2,104	$ 3,327	$ 819	$ 4,895	$ 1,355
Other Reserves:					
Injuries and damages	1,995	890	—	1,011	1,874
2014:					
Reserves deducted from applicable assets					
Reserve for uncollectible accounts	$ 2,502	$ 6,756	$ 198	$ 7,352	$ 2,104
Other Reserves:					
Rate refunds	398	(398)	—	—	—
Injuries and damages	1,671	461	—	137	1,995
2013:					
Reserves deducted from applicable assets					
Reserve for uncollectible accounts	$ 1,873	$ 5,777	$ (38)	$ 5,110	$ 2,502
Other Reserves:					
Rate refunds	—	398	—	—	398
Injuries and damages	5,480	913	—	4,722	1,671

[1] Represents deductions from the reserves for purposes for which the reserves were created. In the case of uncollectible accounts, includes reversals of amounts previously written off.

SIGNATURES

Pursuant to the requirements of Section 13 and 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

February 18, 2016		IDACORP, INC.
Date		
	By:	*/s/ Darrel T. Anderson*
		Darrel T. Anderson President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Robert A. Tinstman Robert A. Tinstman	Chairman of the Board	February 18, 2016
/s/ Darrel T. Anderson Darrel T. Anderson President and Chief Executive Officer and Director	(Principal Executive Officer)	February 18, 2016
/s/ Steven R. Keen Steven R. Keen Senior Vice President, Chief Financial Officer, and Treasurer	(Principal Financial Officer)	February 18, 2016
/s/ Kenneth W. Petersen Kenneth W. Petersen Vice President, Controller, and Chief Accounting Officer	(Principal Accounting Officer)	February 18, 2016
/s/ Thomas Carlile Thomas Carlile	Director	February 18, 2016
/s/ Richard J. Dahl Richard J. Dahl	Director	February 18, 2016
/s/ Ronald W. Jibson Ronald W. Jibson	Director	February 18, 2016
/s/ Judith A. Johansen Judith A. Johansen	Director	February 18, 2016
/s/ Dennis L. Johnson Dennis L. Johnson	Director	February 18, 2016
/s/ J. LaMont Keen J. LaMont Keen	Director	February 18, 2016
/s/ Christine King Christine King	Director	February 18, 2016
/s/ Richard J. Navarro Richard J. Navarro	Director	February 18, 2016

SIGNATURES

Pursuant to the requirements of Section 13 and 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

February 18, 2016		Idaho Power Company
Date		
	By:	*/s/ Darrel T. Anderson*
		Darrel T. Anderson President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

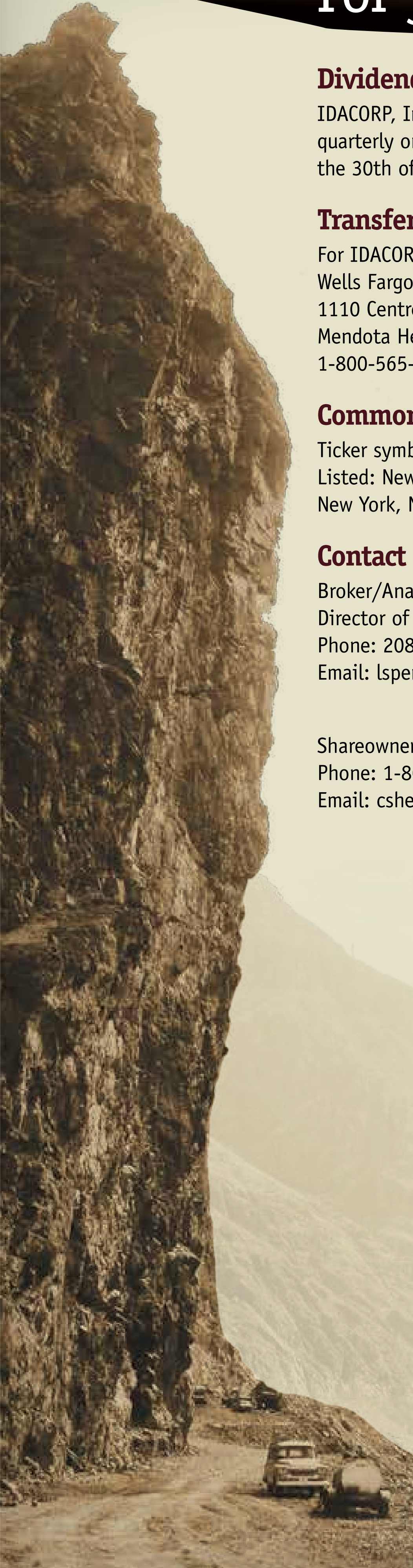
Signature	**Title**	**Date**
/s/ Robert A. Tinstman Robert A. Tinstman	Chairman of the Board	February 18, 2016
/s/ Darrel T. Anderson Darrel T. Anderson President and Chief Executive Officer and Director	(Principal Executive Officer)	February 18, 2016
/s/ Steven R. Keen Steven R. Keen Senior Vice President, Chief Financial Officer, and Treasurer	(Principal Financial Officer)	February 18, 2016
/s/ Kenneth W. Petersen Kenneth W. Petersen Vice President, Controller, and Chief Accounting Officer	(Principal Accounting Officer)	February 18, 2016
/s/ Thomas Carlile Thomas Carlile	Director	February 18, 2016
/s/ Richard J. Dahl Richard J. Dahl	Director	February 18, 2016
/s/ Ronald W. Jibson Ronald W. Jibson	Director	February 18, 2016
/s/ Judith A. Johansen Judith A. Johansen	Director	February 18, 2016
/s/ Dennis L. Johnson Dennis L. Johnson	Director	February 18, 2016
/s/ J. LaMont Keen J. LaMont Keen	Director	February 18, 2016
/s/ Christine King Christine King	Director	February 18, 2016
/s/ Richard J. Navarro Richard J. Navarro	Director	February 18, 2016

EXHIBIT INDEX

Exhibit No.	Description
10.34[1]	IDACORP, Inc. Non-Employee Directors Stock Compensation Plan, as amended November 19, 2015
10.40[1]	IDACORP, Inc. and/or Idaho Power Company Executive Officers with Amended and Restated Change in Control Agreements chart, as of February 12, 2016
10.47[1]	IDACORP, Inc. Executive Incentive Plan, as amended and restated February 11, 2016
10.50[1]	IDACORP, Inc. and Idaho Power Company Compensation for Non-Employee Directors of the Board of Directors, effective January 1, 2016
10.59[1]	Idaho Power Company Restated Employee Savings Plan, as restated as of January 1, 2016
12.1	IDACORP, Inc. Computation of Ratio of Earnings to Fixed Charges and Supplemental Ratio of Earnings to Fixed Charges
12.2	Idaho Power Company Computation of Ratio of Earnings to Fixed Charges and Supplemental Ratio of Earnings to Fixed Charges
23.1	Consent of Independent Registered Public Accounting Firm
23.2	Consent of Independent Registered Public Accounting Firm
31.1	IDACORP, Inc. Rule 13a-14(a) CEO certification
31.2	IDACORP, Inc. Rule 13a-14(a) CFO certification
31.3	Idaho Power Rule 13a-14(a) CEO certification
31.4	Idaho Power Rule 13a-14(a) CFO certification
32.1	IDACORP, Inc. Section 1350 CEO certification
32.2	IDACORP, Inc. Section 1350 CFO certification
32.3	Idaho Power Section 1350 CEO certification
32.4	Idaho Power Section 1350 CFO certification
95.1	Mine safety disclosures
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	XBRL Taxonomy Extension Label Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

[1] Management contract or compensatory plan or arrangement.

For your reference



Dividend Payment Dates

IDACORP, Inc. Common Stock dividends are paid quarterly on or about the 28th of February, and the 30th of May, August and November.

Transfer Agent/Registrar

For IDACORP, Inc. Common Stock
Wells Fargo Shareowner Services
1110 Centre Pointe Curve, Suite 101
Mendota Heights, MN 55120
1-800-565-7890

Common Stock Information

Ticker symbol: IDA
Listed: New York Stock Exchange, 11 Wall St.
New York, NY 10005

Contact

Broker/Analyst Contact: Lawrence F. Spencer
Director of Investor Relations
Phone: 208-388-2664   Fax: 208-333-2372
Email: lspencer@idacorpinc.com

Shareowner Contact: Colette Shepard
Phone: 1-800-635-5406   Fax: 208-388-6955
Email: cshepard@idacorpinc.com

Corporate Headquarters

Mailing: P.O. Box 70, Boise, ID 83707-0070
Street: 1221 W. Idaho St.
Boise, Idaho 83702-5627
Phone: 208-388-2200
Website: idacorpinc.com

SEC Form 10-K

The IDACORP, Inc. and Idaho Power Company combined Form 10-K has been filed with the Securities and Exchange Commission. The Form 10-K and this Annual Report to Shareholders also are available on our website at idacorpinc.com. This report is prepared for the information of shareholders of the company and is not to be used by others in connection with any sale, offer for sale or solicitation of any offer to buy any securities.

2016 Annual Meeting

The 2016 Annual Meeting of Shareholders will be held at Idaho Power's Corporate Headquarters, 1221 W. Idaho St., Boise, Idaho at 10 a.m. local time on Thursday, May 19, 2016. Formal notice of the meeting will be mailed to shareholders on or about Friday, April 1, 2016.

IDACORP, Inc.—Boise, Idaho-based and formed in 1998—is a holding company comprised of Idaho Power Company, a regulated electric utility; IDACORP Financial, a holder of affordable housing projects and other real estate investments; and Ida-West Energy, an operator of small hydroelectric generation projects that satisfy the requirements of the Public Utility Regulatory Policies Act of 1978. IDACORP's origins lie with Idaho Power and operations beginning in 1916. Today, Idaho Power employs approximately 2,000 people to serve a 24,000-square-mile service area in southern Idaho and eastern Oregon. With 17 low-cost hydroelectric projects as the core of its generation portfolio, Idaho Power's nearly 525,000 residential, business and agricultural customers pay some of the nation's lowest prices for electricity. To learn more about Idaho Power or IDACORP, Inc., visit idahopower.com or idacorpinc.com.

Forward-Looking Statements: Please refer to IDACORP's and Idaho Power's Form 10-K for a description of the risks and uncertainties related to the forward-looking statements included in this Annual Report.

Building the Future
100 YEARS
Powering Generations
1916 2016
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P.O. Box 70
Boise, ID 83707-0070

idacorpinc.com