e-FILING REPORT COVER SHEET

COMPANY NAME: Idaho Power Company

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ☒ No ☐ Yes If yes, submit a redacted public version (or a cover letter) by email. Submit the confidential information as directed in OAR 860-001-0070 or the terms of an applicable protective order.

Select report type: ☒ RE (Electric) ☐ RG (Gas) ☐ RW (Water) ☐ RT (Telecommunications)
☐ RO (Other, for example, industry safety information)

Did you previously file a similar report? ☐ No ☒ Yes, report docket number: RE 78

Report is required by: ☐ OAR 860-027-0070
☐ Statute
☐ Order
Note: A one-time submission required by an order is a compliance filing and not a report (file compliance in the applicable docket)
☐ Other
(For example, federal regulations, or requested by Staff)

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

List Key Words for this report. We use these to improve search results.

Send the completed Cover Sheet and the Report in an email addressed to PUC.FilingCenter@state.or.us

Send confidential information, voluminous reports, or energy utility Results of Operations Reports to PUC Filing Center, PO Box 1088, Salem, OR 97308-1088 or by delivery service to 201 High Street SE Suite 100, Salem, OR 97301.

Print

LISA D. NORDSTROM
Lead Counsel
lnordstrom@idahopower.com

April 24, 2019

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 2018 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, 2018. Also included is the IDACORP 2018 Annual Report. Five printed copies of the 2018 Annual Report and two CDs containing the FERC Form 1 Report, accompanying Excel workbooks, and the 2018 Annual Report are being sent via U.S. Mail, as requested.

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 12/31/2019)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2019)
Form 3-Q Approved
OMB No.1902-0205
(Expires 12/31/2019)

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** 2018/Q4

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

Form 1 Approved
OMB No.1902-0021
(Expires 12/31/2019)
Form 1-F Approved
OMB No.1902-0029
(Expires 12/31/2019)
Form 3-Q Approved
OMB No.1902-0205
(Expires 12/31/2019)

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

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Exact Legal Name of Respondent (Company)	**Year/Period of Report**
Idaho Power Company	**End of** 2018/Q4

Deloitte.

Deloitte & Touche LLP
800 West Main Street
Suite 1400
Boise, ID 83702-7734
USA

Tel: +1 208 342 9361
www.deloitte.com

INDEPENDENT AUDITORS' REPORT

Idaho Power Company
Boise, Idaho

We have audited the accompanying financial statements of Idaho Power Company (the "Company"), which comprise the balance sheet - regulatory basis as of December 31, 2018, and the related statements of income - regulatory basis, retained earnings - regulatory basis, and cash flows - regulatory basis for the year then ended, included on pages 110 through 123 of the accompanying Federal Energy Regulatory Commission Form 1, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Company's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the regulatory-basis financial statements referred to above present fairly, in all material respects, the assets, liabilities, and proprietary capital of Idaho Power Company as of December 31, 2018, and the results of its operations and its cash flows for the year then ended in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases.

Basis of Accounting

As discussed in Note 1 to the financial statements, these financial statements were prepared in accordance with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a basis of accounting other than accounting principles generally accepted in the United States of America. Our opinion is not modified with respect to this matter.

Restricted Use

This report is intended solely for the information and use of the board of directors and management of the Company and for filing with the Federal Energy Regulatory Commission and is not intended to be and should not be used by anyone other than these specified parties.

Deloitte & Touche LLP

April 16, 2019

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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	02 Year/Period of Report
Idaho Power Company	End of 2018/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	06 Title of Contact Person
Ken Petersen	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*	09 This Report Is	10 Date of Report *(Mo, Da, Yr)*
(208) 388-2761	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019

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	03 Signature	04 Date Signed *(Mo, Da, Yr)*
Ken Petersen	Ken Petersen	04/16/2019
02 Title		
Vice President, Controller & CAO		

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) 04/16/2019	Year/Period of Report End of 2018/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".

LIST OF SCHEDULES (Electric Utility) (continued)

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

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/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: [ ] 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	04/16/2019	End of 2018/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

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	04/16/2019	End of 2018/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	04/16/2019	End of 2018/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	860,000
3			
4	Senior Vice President, CFO & Treasurer	Steven Keen	445,000
5			
6	Senior Vice President, COO	Lisa Grow	445,000
7			
8	Senior Vice President, Public Affairs	Jeffrey Malmen	305,000
9			
10	Senior Vice President, Admin Services & Chief HR Officer	Lonnie Krawl (1)	187,000
11			
12	Senior Vice President & General Counsel	Brian Buckham	340,000
13			
14	Vice President, T&D Engineering & Construction, and CSO	Vern Porter	305,000
15			
16	Vice President, Power Supply	Tessia Park	285,000
17			
18	Vice President, Customer Operations & Bus. Development	Adam Richins	260,000
19			
20	Vice President, Corporate Controller & CAO	Ken Petersen	265,000
21			
22	Vice President of Corporate Services & CIO	Jeff Glenn	262,000
23			
24	Vice President of Regulatory Affairs	Tim Tatum	200,000
25			
26	Corporate Secretary	Patrick Harrington	210,000
27			
28	(1) Retirement effective 8/31/18, Salary shows YTD wages		
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DIRECTORS

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

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1		
2	Judith A. Johansen	10446 E. Palo Brea Dr., Scottsdale, Arizona 85262
3		
4	Christine King, Comp. Committee Chair,***	8527 East Old Field Rd
5		Scottsdale, Arizona 85266
6		
7	Thomas E. Carlile	2719 North Woodview place, Boise Idaho 83702
8		
9	Darrel T. Anderson President & CEO, ** ***	Idaho Power Company, 1221 W. Idaho Street,
10		P.O. Box 70, Boise, Idaho 83707-0070
11		
12	J. LaMont Keen (1)	481 North Strata Via Way, Boise Idaho 83712
13		
14	Robert A. Tinstman, Board Chair & Corp Gov Chair, ***	4433 W. Quail Point Court, Boise, Idaho 83703
15		
16	Richard Dahl, Audit Chair ***	60 Laiki Pl.
17		Kailua, Hawaii 96734-1905
18		
19	Dennis L. Johnson	926 W Oakhampton Dr, Eagle, Idaho 83616
20		
21	Ronald W. Jibson	417 Aerie Circle, North Salt Lake City, Utah 84054
22		
23	Richard J. Navarro	1256 E. Candleridge Ct., Boise, Idaho 83712
24		
25	Annette G. Elg	3475 E. Rivernest Lane, Boise, Idaho 83706-6928
26		
27	(1) Retired on May 16, 2018	
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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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	20180829-5166	08/29/2018	ER09-1641-000	Idaho Power Company	FERC Electric Tariff
2				2018 Annual	
3				Informational Filling	
4				under ER09-1641-000	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	04/16/2019	End of 2018/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. None

4. None

5. None

6. In March 2018, Idaho Power issued $220 million in principal amount of 4.20% first mortgage bonds, secured medium-term notes, Series K, maturing on March 1, 2048. In April and May 2016, 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. The order from the IPUC approved the issuance of the securities through May 31, 2019, subject to extensions upon request to the IPUC. The OPUC's and WPSC's orders do not impose a time limitation for issuances, but the OPUC order does impose a number of other conditions, including a requirement that the interest rates for the debt securities or first mortgage bonds fall within either (a) designated spreads over comparable U.S. Treasury rates or (b) a maximum all-in interest rate limit of 7.0 percent.

7. None

8. Effective 12/28/2018 a 3.0% general wage adjustment was implemented.

9. None

10. None

11. Reserved

12. None

13. Officer Changes in 2018

    - Jeff S. Glenn's title changed from "Vice President of Information Technology and Chief Information Officer" to "Vice President of Corporate Services and Chief Information Officer" effective June 2, 2018.
    - Lonnie G. Krawl retired as Senior Vice President of Administrative Services and Chief Human Resources Officer on August 31, 2018.

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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	6,108,607,184	5,914,236,887
3	Construction Work in Progress (107)	200-201	480,258,675	452,424,340
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		6,588,865,859	6,366,661,227
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	2,394,578,627	2,283,266,546
6	Net Utility Plant (Enter Total of line 4 less 5)		4,194,287,232	4,083,394,681
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)		4,194,287,232	4,083,394,681
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		3,653,100	1,071,638
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	57,026,771	72,212,978
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)		0	0
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		36,487,611	30,265,777
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	4,074
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	0
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		97,167,482	103,554,467
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		86,225,120	34,375,147
36	Special Deposits (132-134)		1,167,693	2,364,499
37	Working Fund (135)		7,000	10,500
38	Temporary Cash Investments (136)		79,228,007	10,260,000
39	Notes Receivable (141)		-84,743	-86,399
40	Customer Accounts Receivable (142)		79,182,408	77,764,379
41	Other Accounts Receivable (143)		6,330,066	28,169,330
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		1,989,131	2,192,252
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		0	0
45	Fuel Stock (151)	227	47,979,122	56,638,459
46	Fuel Stock Expenses Undistributed (152)	227	0	5
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	53,553,674	53,856,630
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

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	1,433,652	1,888,307
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)		16,373,874	16,865,877
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		56,822	6,500
60	Rents Receivable (172)		0	0
61	Accrued Utility Revenues (173)		69,318,168	75,119,761
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		3,655,138	22,228
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	4,074
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)		442,436,870	355,058,897
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		15,958,660	15,097,172
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	1,214,174,417	1,132,096,194
73	Prelim. Survey and Investigation Charges (Electric) (183)		0	0
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)		2,005,924	535,559
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	73,405,043	73,132,688
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)		42,445,540	39,822,616
82	Accumulated Deferred Income Taxes (190)	234	293,383,262	289,813,919
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		1,641,372,846	1,550,498,148
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		6,375,264,430	6,092,506,193

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	end of 2018/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	1,354,681,706	1,234,859,727
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	54,563,677	69,749,884
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)	-22,843,785	-26,872,209
16	Total Proprietary Capital (lines 2 through 15)		2,194,439,138	2,085,774,942
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	1,835,460,000	1,745,460,000
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	19,885,000	19,885,000
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		4,598,059	4,124,868
24	Total Long-Term Debt (lines 18 through 23)		1,850,746,941	1,761,220,132
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)		1,811,302	1,468,935
29	Accumulated Provision for Pensions and Benefits (228.3)		431,492,131	438,886,025
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		136,505,890	119,666,875
32	Long-Term Portion of Derivative Instrument Liabilities		63,744	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	0
34	Asset Retirement Obligations (230)		26,791,608	26,415,381
35	Total Other Noncurrent Liabilities (lines 26 through 34)		596,664,675	586,437,216
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		134,836,251	107,891,859
39	Notes Payable to Associated Companies (233)		4,552,447	4,083,304
40	Accounts Payable to Associated Companies (234)		2,088,345	57,561,953
41	Customer Deposits (235)		1,342,506	2,037,068
42	Taxes Accrued (236)	262-263	1,306,621	-15,156,342
43	Interest Accrued (237)		23,857,084	22,620,139
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		2,224,148	2,751,894
48	Miscellaneous Current and Accrued Liabilities (242)		56,428,043	50,874,603
49	Obligations Under Capital Leases-Current (243)		0	0
50	Derivative Instrument Liabilities (244)		974,268	1,224,571
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		63,744	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)		227,545,969	233,889,049
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		5,156,242	6,762,256
57	Accumulated Deferred Investment Tax Credits (255)	266-267	92,789,836	87,384,738
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	8,306,007	8,746,270
60	Other Regulatory Liabilities (254)	278	351,782,980	307,404,206
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)		908,615,099	890,330,923
64	Accum. Deferred Income Taxes-Other (283)		139,217,543	124,556,461
65	Total Deferred Credits (lines 56 through 64)		1,505,867,707	1,425,184,854
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		6,375,264,430	6,092,506,193

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	1,361,957,450	1,340,860,404		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	800,135,259	769,799,625		
5	Maintenance Expenses (402)	320-323	69,035,321	60,983,589		
6	Depreciation Expense (403)	336-337	156,332,587	153,958,586		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	566,665	566,665		
8	Amort. & Depl. of Utility Plant (404-405)	336-337	6,981,078	6,243,722		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337	15,018	32,539		
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)					
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		6,802,055	1,289,770		
13	(Less) Regulatory Credits (407.4)		2,167,344	-788,738		
14	Taxes Other Than Income Taxes (408.1)	262-263	34,792,143	34,089,536		
15	Income Taxes - Federal (409.1)	262-263	20,035,445	44,701,501		
16	- Other (409.1)	262-263	-2,242,797	10,557,960		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	37,060,319	54,908,265		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	44,435,246	80,542,460		
19	Investment Tax Credit Adj. - Net (411.4)	266	5,405,098	7,424,893		
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)		154,940	130,740		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)		227,740	221,929		
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		1,088,388,401	1,064,894,118		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		273,569,049	275,966,286		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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
1,361,957,450	1,340,860,404					2
						3
800,135,259	769,799,625					4
69,035,321	60,983,589					5
156,332,587	153,958,586					6
566,665	566,665					7
6,981,078	6,243,722					8
15,018	32,539					9
						10
						11
6,802,055	1,289,770					12
2,167,344	-788,738					13
34,792,143	34,089,536					14
20,035,445	44,701,501					15
-2,242,797	10,557,960					16
37,060,319	54,908,265					17
44,435,246	80,542,460					18
5,405,098	7,424,893					19
						20
						21
154,940	130,740					22
						23
227,740	221,929					24
1,088,388,401	1,064,894,118					25
273,569,049	275,966,286					26

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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	04/16/2019	End of 2018/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)		273,569,049	275,966,286		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)		3,971,967	4,032,474		
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		4,003,151	4,104,918		
33	Revenues From Nonutility Operations (417)		25,046	28,462		
34	(Less) Expenses of Nonutility Operations (417.1)		12,425	61,905		
35	Nonoperating Rental Income (418)		-3,351	-7,437		
36	Equity in Earnings of Subsidiary Companies (418.1)	119	8,813,793	7,082,051		
37	Interest and Dividend Income (419)		8,923,003	6,043,906		
38	Allowance for Other Funds Used During Construction (419.1)		24,352,523	20,784,392		
39	Miscellaneous Nonoperating Income (421)		79,416	253,942		
40	Gain on Disposition of Property (421.1)		264,632	450,000		
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		42,411,453	34,500,967		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		48,950			
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		811,136	881,377		
46	Life Insurance (426.2)		-2,779,387	-2,089,825		
47	Penalties (426.3)		40,155	14,381		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		1,203,610	1,442,703		
49	Other Deductions (426.5)		7,820,081	8,164,084		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		7,144,545	8,412,720		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	19,680	20,222		
53	Income Taxes-Federal (409.2)	262-263	627,071	20,849		
54	Income Taxes-Other (409.2)	262-263	193,942	3,721		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	261,601	13,168,748		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	770,831	1,248,722		
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)		331,463	11,964,818		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		34,935,445	14,123,429		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		84,407,634	81,198,430		
63	Amort. of Debt Disc. and Expense (428)		1,606,787	1,508,990		
64	Amortization of Loss on Reaquired Debt (428.1)		2,152,952	2,152,952		
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)		279,757	81,933		
68	Other Interest Expense (431)		7,874,386	7,494,378		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		10,151,313	8,694,285		
70	Net Interest Charges (Total of lines 62 thru 69)		86,170,203	83,742,398		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		222,334,291	206,347,317		
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)		222,334,291	206,347,317		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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		1,221,586,621	1,123,606,367
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4	Benefit Plan Tax Reform Adjustment		4,092,208	
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)		4,092,208	
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		213,520,498	199,202,985
17	Appropriations of Retained Earnings (Acct. 436)			
18				
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)			
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31			-121,790,727	(113,285,012)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-121,790,727	(113,285,012)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings		24,000,000	12,062,281
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		1,341,408,600	1,221,586,621
	APPROPRIATED RETAINED EARNINGS (Account 215)			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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)		1,354,681,706	1,234,859,727
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		69,749,884	74,667,833
50	Equity in Earnings for Year (Credit) (Account 418.1)		8,813,793	7,082,051
51	(Less) Dividends Received (Debit)		24,000,000	12,000,000
52				
53	Balance-End of Year (Total lines 49 thru 52)		54,563,677	69,749,884

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Schedule Page: 118 Line No.: 9 Column: c

In November 2018, the FERC issued a final accounting order allowing certain entities, including Idaho Power, to make a policy election to reclassify the stranded tax effects resulting from income tax reform from AOCI to retained earnings in accordance with ASU 2018-02, *Income Statement—Reporting Comprehensive Income (Topic 220)*. In 2018, Idaho Power transferred $4.1 million from AOCI to retained earnings.

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/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)	222,334,291	206,347,317
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	156,332,587	153,958,586
5	Amortization of	12,186,464	11,378,099
6			
7			
8	Deferred Income Taxes (Net)	-1,689,885	14,370,999
9	Investment Tax Credit Adjustment (Net)	1,496,757	-20,660,275
10	Net (Increase) Decrease in Receivables	633,606	-2,496,038
11	Net (Increase) Decrease in Inventory	9,463,201	-809,418
12	Net (Increase) Decrease in Allowances Inventory		
13	Net Increase (Decrease) in Payables and Accrued Expenses	-9,272,216	36,135,459
14	Net (Increase) Decrease in Other Regulatory Assets	30,090,539	39,149,025
15	Net Increase (Decrease) in Other Regulatory Liabilities	18,301,367	17,982,095
16	(Less) Allowance for Other Funds Used During Construction	24,352,523	20,784,392
17	(Less) Undistributed Earnings from Subsidiary Companies	-15,186,207	-4,917,949
18	Other (provide details in footnote):	-12,704,289	-22,985,607
19			
20			
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	418,006,106	416,503,799
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-302,175,811	-306,254,955
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	-24,352,523	-20,784,392
31	Other (provide details in footnote):	25,112,774	8,397,326
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-252,710,514	-277,073,237
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	-1,655	3,362
40	Contributions and Advances from Assoc. and Subsidiary Companies	469,143	3,838,869
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)	-11,390,307	-11,356,339
45	Proceeds from Sales of Investment Securities (a)	5,007,519	4,989,363

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	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):	795,456	-11,959
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-257,830,358	-279,609,941
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	220,000,000	
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)	220,000,000	
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-130,000,000	-1,063,634
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):	-7,570,541	-240,000
77			
78	Net Decrease in Short-Term Debt (c)		-21,800,000
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-121,790,727	-113,285,012
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-39,361,268	-136,388,646
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	120,814,480	505,212
87			
88	Cash and Cash Equivalents at Beginning of Period	44,645,647	44,140,435
89			
90	Cash and Cash Equivalents at End of period	165,460,127	44,645,647

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

Amortization

Plant	6,996,096
Unamortized debt expense	3,786,635
Unamortized discount	297,956
Water rights	1,042,009
Other	63,768
	12,186,464

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

Cash (received) paid during the period for:

Income taxes	58,703,841
Interest (net of amount capitalized)	80,893,762

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

Cash Flow from Operating Activities (Other)

Pension and postretirement benefit plan expense	32,239,953
Contributions to pension and postretirement benefit plans	(45,883,362)
Unbilled revenues	6,157,496
Accrued payroll	2,137,367
Prepayments	(2,913,828)
Deposits from third parties	(2,300,576)
Other	(2,141,339)
	(12,704,289)

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

Non-cash investing activities:

Additions to PP&E in accounts payable	29,528,490

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

Other Cash Flows from Plant

Payments received from joint funding partners	21,586,687
Sale of renewable energy certificates and emission allowances	3,052,681
Sale of utility property	473,406
	25,112,774

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

Other Investing Cash Flows

Life Insurance Proceeds- net of premiums	795,456
	795,456

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

Other Financing Cash Flows

Make-whole premium on retirement of long-term debt	(4,606,943)
Debt issuance costs	(2,149,598)
Discount on debt issuance	(814,000)
	(7,570,541)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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				(20,881,620)
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				1,882,086
3	Preceding Quarter/Year to Date Changes in Fair Value				(7,872,675)
4	Total (lines 2 and 3)				(5,990,589)
5	Balance of Account 219 at End of Preceding Quarter/Year				(26,872,209)
6	Balance of Account 219 at Beginning of Current Year				(26,872,209)
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				2,885,872
8	Current Quarter/Year to Date Changes in Fair Value				1,142,552
9	Total (lines 7 and 8)				4,028,424
10	Balance of Account 219 at End of Current Quarter/Year				(22,843,785)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Insert Footnote at Line 1 to 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			(20,881,620)		
2			1,882,086		
3			(7,872,675)		
4			(5,990,589)	206,347,317	200,356,728
5			(26,872,209)		
6			(26,872,209)		
7			2,885,872		
8			1,142,552		
9			4,028,424	222,334,291	226,362,715
10			(22,843,785)		

NOTES TO FINANCIAL STATEMENTS

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

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SEE PAGE 123 FOR REQUIRED INFORMATION.

IDAHO POWER COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Idaho Power Company (Idaho Power) is the principal operating subsidiary of IDACORP, Inc. (IDACORP), a holding company formed in 1998. Idaho Power is an electric utility engaged in the generation, transmission, distribution, sales, and purchase of electric energy and capacity with a service area covering approximately 24,000 square miles in southern Idaho and eastern Oregon. Idaho Power is regulated primarily by the state utility regulatory commissions of Idaho and Oregon and the Federal Energy Regulatory Commission (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.

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 financial statements in conformity with generally accepted accounting principles. These estimates and assumptions include those related to rate regulation, retirement benefits, contingencies, 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. Accordingly, actual results could differ from those estimates.

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. 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 effects of applying these regulatory accounting principles to Idaho Power's operations are discussed in more detail in Note 3 - "Regulatory Matters."

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.

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 per month 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 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, 2018 and 2017. 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

On January 1, 2018, IDACORP and Idaho Power adopted Accounting Standards Update (ASU) 2014-09, *Revenue from Contracts with Customers (Topic 606)*. The adoption did not change the timing or amounts of revenue recognized by IDACORP or Idaho Power.

Operating revenues are generally recorded when service is rendered or energy is delivered to customers. Idaho Power accrues estimated unbilled revenues for electric services delivered to customers but not yet billed at year-end. Idaho Power does not report any collections of franchise fees and similar taxes related to energy consumption on the income statement. In addition, regulatory mechanisms in place in Idaho and Oregon affect the reported amount of revenue. The effects of applying these regulatory mechanisms are discussed in more detail in Note 4 - "Revenues."

Property, Plant and Equipment and Depreciation

The cost of utility plant in service represents the original cost of contracted services, direct labor and material, allowance for funds used during construction (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 2.8 percent in 2018 and 2.9 percent in 2017.

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 2018 or 2017.

Allowance for Funds Used During Construction

AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. With one exception, for the Hells Canyon Complex (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 2018 and 2017.

Income Taxes

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 record 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.

IDACORP and Idaho Power use judgment, estimation, and historical data in developing the provision for income taxes and the reporting of tax-related assets and liabilities, including development of current year tax depreciation, capitalized repair costs, capitalized overheads, and other items. Income taxes can be impacted by changes in tax laws and regulations, interpretations by taxing authorities, changes to accounting guidance, and actions by federal or state public utility regulators. 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.

In compliance with the federal income tax requirements for the use of accelerated tax depreciation, Idaho Power records 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 recorded 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 - "Income Taxes."

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.

Reclassifications

In these consolidated financial statements, certain amounts in prior periods' consolidated financial statements have been reclassified to conform with current period presentation. On Idaho Power's December 31, 2017, consolidated balance sheet, the "Long-term receivables" balance of $0.5 million which had previously been reported separately, was reclassified to "Deferred Debits."

New and Recently Adopted Accounting Pronouncements

Recently Adopted Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board (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 FASB amended certain aspects of ASU 2014-09 to clarify the implementation guidance, including clarifications related to principal versus agent considerations, licensing and identifying performance obligations, narrow scope improvements, and practical expedients. Idaho Power adopted ASU 2014-09 on January 1, 2018, using the modified-retrospective approach as provided for in the standard. The adoption did not change the timing or amounts of revenue currently recognized by the companies, so no cumulative-effect adjustment was required. The adoption did change presentation of revenues on the consolidated statements of income and also added disclosures. To conform with current period presentation, "Electric utility revenues" and "Operating Revenues" on Idaho Power's consolidated statements of income for the years ended December 31, 2018 and 2017, which had previously been reported separately as "General business," "Off-system sales," and "Other revenues," are no longer reported separately. See Note 4 - "Revenues" for additional information on the disaggregation of revenue and additional disclosures.

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 adopted ASU 2016-01 on January 1, 2018. The adoption did not have a material impact on the companies' financial statements as the companies previously elected the fair value option and reported available-for-sale securities at fair value.

In August 2016, the FASB issued ASU 2016-15, *Statement of Cash Flows (Topic 230) Classification of Certain Cash Receipts and Cash Payments*, to reduce diversity in practice in how certain cash receipts and cash payments are classified in the statement of cash flows. The companies' classification of proceeds from the settlement of corporate-owned life insurance policies and related costs will be classified as investing activities under the new guidance. The new guidance did not affect the companies' presentation of debt prepayment and extinguishment costs, proceeds from the settlement of insurance claims (other than corporate-owned life insurance), and distributions received from equity-method investments. Idaho Power adopted ASU 2016-15 on January 1, 2018, using the retrospective approach as provided for in the standard. To conform with current period presentation, the companies reclassified $3.0 million and $3.6 million of company-owned life insurance proceeds received, for the year ended December 31, 2017 and 2016, respectively, from "Change in accounts receivable" and $0.1 million and $0.1 million of prepaid insurance premiums paid, for the year ended December 31, 2017 and 2016, respectively, from "Change in other assets" (net reclassification of $2.9 million and $3.5 million, respectively) within "Operating Activities" to "Other" within "Investing Activities" on the consolidated statement of cash flows.

In March 2017, the FASB issued ASU 2017-07, *Compensation -- Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost,* which requires employers to disaggregate the service cost component from other components of net periodic benefit costs and to disclose the amounts of net periodic benefit costs that are included in each income statement line item. The standard requires employers to present the service cost component in the same line item as other compensation costs and to present the other components of net periodic benefit cost (which include interest costs, expected return on plan assets, amortization of prior service cost or credits and actuarial gains and losses) separately and outside a subtotal of operating income. In addition, only the service cost component is eligible for capitalization. Idaho Power capitalizes amounts of pension or postretirement costs that are insignificant to the consolidated financial statements. The amendments in ASU 2017-07 are effective for interim and annual reporting periods beginning after December 15, 2017. Entities must use (1) a retrospective transition method to adopt the requirement for separate presentation in the income statement of service costs and other components and (2) a prospective transition method to adopt the requirement to limit the capitalization of benefit costs to the service cost component. Idaho Power adopted ASU 2017-07 on January 1, 2018, and accordingly, have retrospectively adjusted prior periods to reflect the disaggregation of service cost from other components of net periodic benefit costs. The adoption did not have a material impact on the company's financial statements nor did it affect net income for the year ended December 31, 2018. For the years ended December 31, 2017 and 2016, $3.0 million and $2.6 million, respectively, was reclassified from "Other operations and maintenance" to "Other expense, net" to conform to current period presentation.

Recent Accounting Pronouncements Not Yet Adopted

In August 2018, the FASB issued ASU 2018-15, *Intangibles—Goodwill and Other—Internal-Use Software (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract*, to provide guidance on implementation costs incurred in a cloud computing arrangement that is a service contract. ASU 2018-15 aligns the accounting for such costs with the guidance on capitalizing costs associated with developing or obtaining internal-use software. The new standard is effective for interim and annual reporting periods beginning after December 15, 2019, with early adoption permitted. Idaho Power are evaluating the impact of ASU 2018-15 on their respective financial statements.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842),* intended to improve financial reporting about leasing transactions. The ASU requires lessees to recognize a right-of-use asset and lease liability on the balance sheet for most leases. In addition, the ASU revises the definition of a lease in regards to when an arrangement conveys the right to control the use of the identified asset under the arrangement, which may result in changes to the classification of an arrangement as a lease. ASU 2016-02 was effective on January 1, 2019, and Idaho Power will record any effects of the adoption in the first quarter of 2019. While Idaho Power is finalizing the assessment of the financial impacts of the adoption, the adoption of ASU 2016-02 will not have a material impact on their respective financial statements.

Subsequent Events

Management has evaluated the impact of events occurring after December 31, 2018, up to February 21, 2019, 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, 2019. 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 (dollars in thousands):

	2018	2017
Federal income tax expense at 21% statutory rate	$ 50,078	$ 89,370
Change in taxes resulting from:		
Equity earnings of subsidiary companies	(1,851.00)	(2,479.00)
AFUDC	(7,246.00)	(10,318.00)
Capitalized interest	928.00	1,513.00
Investment tax credits	(2,929.00)	(3,081.00)
Bond redemption costs	(1,029.00)	0.00
Removal costs	(3,471.00)	(6,280.00)
Capitalized overhead costs	(6,720.00)	(11,200.00)
Capitalized repair costs	(17,850.00)	(28,700.00)
State income taxes, net of federal benefit	8,532.00	8,108.00
Depreciation	13,110.00	18,953.00
Excess deferred income tax reversal	(7,289.00)	0.00
Stock-based compensation	(883.00)	(1,483.00)
Remeasurement of deferred taxes	(5,620.00)	2,623.00
Income tax return adjustments	(4,882.00)	(3,875.00)
Other, net	3,257.00	(4,156.00)
Total income tax expense	$ 16,135	$ 48,995
Effective tax rate	6.8%	19.2%

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

	2018	2017
Income taxes currently payable:		
Federal	20,663	44,722
State	(2,049)	10,562
Total	18,614	55,284
Income taxes deferred:		
Federal	(13,309)	(8,416)
State	5,425	(5,298)
Total	(7,884)	(13,714)
Investment tax credits:		
Deferred	8,334	10,506
Restored	(2,929)	(3,081)
Total	5,405	7,425
Total income tax expense	$ 16,135	$ 48,995

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

	2018	2017
Deferred tax assets:		
Regulatory liabilities	$ 98,042	$ 98,744
Deferred compensation	21,826	21,025
Deferred revenue	35,137	31,086
Tax credits	44,408	43,995
Retirement benefits	91,867	94,493
Other	9,122	8,435
Total	300,402	297,778
Deferred tax liabilities:		
Property, plant and equipment	294,471	306,002
Regulatory assets	614,144	584,329
Fixed cost adjustment	10,940	8,016
Retirement benefits	108,440	103,407
Other	26,855	21,097
Total	1,054,850	1,022,851
Net deferred tax liabilities	$ 754,448	$ 725,073

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 and are reported as taxes accrued or income taxes receivable, respectively, on the consolidated balance sheets of Idaho Power. See Note 1 - "Summary of Significant Accounting Policies" for further discussion of accounting policies related to income taxes.

Uncertain Tax Positions

Idaho Power believes that it has no material income tax uncertainties for 2018 and prior tax years. The Company recognizes interest accrued related to unrecognized tax benefits as interest expense and penalties as other expense.

Idaho Power is subject to examination by its major tax jurisdictions - U.S. federal and the State of Idaho. The open tax years for examination are 2018 for federal and 2014-2018 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 2018, the IRS completed its examination of IDACORP's 2017 tax year with no unresolved income tax issues.

Income Tax Reform

In December 2017, the Tax Cuts and Jobs Act was signed into law, which significantly reforms the Internal Revenue Code of 1986, as amended. Effective January 1, 2018, the Tax Cuts and Jobs Act permanently lowers the corporate tax rate to 21 percent from the existing maximum rate of 35 percent, provides for expanded bonus depreciation, limits the deductibility of interest expense, eliminates the alternative minimum tax, repeals the manufacturing deduction, and imposes additional limitations on the deductibility of executive compensation. Public utility companies, such as Idaho Power, retain the deductibility of interest expense and are excluded from the bonus depreciation provisions; however, traditional accelerated tax depreciation methods are still available.

Due to the enactment of the Tax Cuts and Jobs Act and following generally accepted accounting principles, at December 31, 2017, Idaho Power remeasured all deferred income tax assets and liabilities. The effects of these adjustments resulted in a net tax expense for 2017, as shown in the rate reconciliation table above. Also, as shown above, in 2018, a net tax benefit was recognized for the remeasurement of deferred taxes for the adjustment of temporary differences as a result of IDACORP's 2017 consolidated income tax return filings.

Additionally, in 2017, the net deferred tax liabilities decreased by approximately $672 million. Idaho Power's regulatory asset deferred income tax liability item decreased as the related regulatory asset was reduced in two primary ways: (1) the decrease in the federal income tax rate decreased the future cost to customers for funding the net deferred income tax liabilities resulting from the cumulative impacts of using the flow-through income tax accounting method for regulatory purposes and (2) the decrease in the federal income tax rate also reduced the net-to-gross multiplier that increases the regulatory asset to a revenue requirement carrying value. The change in income tax law also reduced the deferred income tax liability for depreciation-related timing differences under the normalized tax accounting method. As this reduction will flow back to customers in the future under the statutorily prescribed average rate assumption method, it was recorded as a regulatory liability on the consolidated balance sheets of the companies.

On March 12, 2018, Idaho House Bill 463 was enacted which lowered the Idaho state corporate income tax rate from 7.4 percent to 6.925 percent effective January 1, 2018. The Idaho tax rate reduction did not have a material impact on Idaho Power's 2018 income tax expense or deferred tax asset and liability balances.

Policy Statement PL19-2-000 Disclosures

Idaho Power’s accumulated deferred income tax (ADIT) accounts (190, 282, 283) and income tax-related regulatory asset and liability accounts (182.3 and 254) were adjusted for the impacts from the income tax reform described above. ADIT accounts were remeasured by first recalculating deferred income tax balances by applying the new 21% statutory corporate tax rate to existing temporary differences. The remeasured balances were then compared to the deferred income tax balances on Idaho Power’s books prior to income tax reform. The difference in the balances resulted in excess ADIT (254 account), no deficient ADIT, and a reduction to Idaho Power’s regulatory asset (182.3 account) for flow-through income tax accounting differences and regulatory liability for investment tax credits (254 account).

The excess ADIT balance as of December 31, 2017 was $194.0 million. A 2017 tax return adjustment of $3.4 million was recorded in the current year which increased the balance of excess ADIT to $197.4 million. All of Idaho Power’s excess ADIT is protected. Unprotected temporary differences were either subject to Idaho Power’s flow-through regulatory income tax accounting method or the remeasured amounts were immaterial. The remeasurement of unprotected items resulted in a $2.6 million net income tax expense in 2017 and a $5.6 million net income tax benefit in 2018 for items adjusted due to the filing of 2017 income tax returns.

Idaho Power’s protected excess ADIT will be returned through rates as the underlying temporary differences reverse using the statutorily prescribed Average Rate Assumption Method (ARAM). For the year ended December 31, 2018, a $7.3 million tax benefit was recorded in account 411.1 for the reversal of excess ADIT. The excess ADIT will be included in rates for both rate base (254 account balance) and cost of service (annual amortization pursuant to ARAM) when future general rate cases are filed for state regulatory jurisdictions and beginning with Idaho Power’s 2019 formula rate filing for FERC purposes.

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 some expenses and revenues in a different period than when an unregulated enterprise would record those 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, 2018: Earning a Return [1]	As of December 31, 2018: Not Earning a Return	Total as of December 31, 2018	Total as of December 31, 2017
Regulatory Assets:					
Income taxes [2]		$ —	$ 614,144	$ 614,144	$ 584,329
Unfunded postretirement benefits [3]		—	278,674	278,674	280,166
Pension expense deferrals		126,811	21,025	147,836	127,721
Energy efficiency program costs [4]		1,398	—	1,398	6,273
Power supply costs [5]		—	—	—	3,137
Fixed cost adjustment [5]	2019-2020	34,502	8,001	42,503	30,856
Valmy Plant settlements [5]	2019-2028	77,512	—	77,512	44,633
Asset retirement obligations [6]		—	17,655	17,655	15,767
Long-term service agreement	2019-2043	16,095	10,653	26,748	27,907
Other	2019-2055	720	6,984	7,704	11,307
Total		$ 257,038	$ 957,136	$ 1,214,174	$ 1,132,096
Regulatory Liabilities:					
Income taxes [7]		$ —	$ 98,042	$ 98,042	$ 98,744
Depreciation-related excess deferred income taxes [8]		190,062	—	190,062	193,991
Energy efficiency program costs [4]		5,259	—	5,259	408
Power supply costs [5]	2019-2020	35,815	6,507	42,322	5,443
Settlement agreement sharing mechanism [5]	2019-2020	5,025	—	5,025	—
Mark-to-market assets [9]		—	3,700	3,700	22
Other		2,419	6,314	8,733	8,796
Total		$ 238,580	$ 114,563	$ 353,143	$ 307,404

(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 flow-through income tax accounting differences which have a corresponding deferred tax liability disclosed in Note 2 - "Income Taxes."
(3) Represents the unfunded obligation of Idaho Power's pension and postretirement benefit plans, which are discussed in Note 11 - "Benefit Plans."
(4) The energy efficiency asset represents the Oregon jurisdiction balance and the liability represents the Idaho jurisdiction balance.
(5) This item is discussed in more detail in this Note 3 - "Regulatory Matters."
(6) Asset retirement obligations are discussed in Note 13 - "Asset Retirement Obligations."
(7) Represents the tax gross-up related to the depreciation-related excess deferred income taxes and investment tax credits included in this table and has a corresponding deferred tax asset disclosed in Note 2 - "Income Taxes."
(8) The Tax Cuts and Jobs Act, enacted on December 22, 2017, reduced the deferred income tax assets and liabilities. For depreciation-related timing differences under the normalized tax accounting method, this reduction will flow back to customers under the statutorily prescribed average rate assumption method.
(9) Mark-to-market assets and liabilities are discussed in Note 16 - "Fair Value Measurements."

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 mechanisms address the volatility of power supply costs and provide for annual adjustments to the rates charged to its retail customers. The power cost adjustment mechanisms compare Idaho Power's actual net power supply costs (primarily fuel and purchased power less wholesale energy sales) against net power supply costs being recovered in Idaho Power's retail rates. Under the power cost adjustment mechanisms, certain differences between actual net power supply costs incurred by Idaho Power and costs being recovered in retail rates 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. The Idaho deferral period or Idaho-jurisdiction power cost adjustment (PCA) year runs from April 1 through March 31. Amounts deferred during the PCA year are primarily recovered or refunded during the subsequent June 1 through May 31 period.

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 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 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, 2018	$ (30.4)	The $30.4 million total decrease in PCA rates includes a $7.8 million one-time benefit for income tax benefits accrued from January 1 to May 31, 2018, and the income taxes related to Idaho Power's open access transmission tariff (OATT) rate. See "Income Tax Reform - Regulatory Treatment" below for more information.
June 1, 2017	$ 10.6	The net increase in PCA rates included an offsetting $13.0 million reduction for the refund of previously collected Idaho energy efficiency rider funds.

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 (Oregon ROE) for the year is at least 100 basis points below Idaho Power's last authorized Oregon ROE. A refund to customers will occur only to the extent that Idaho Power's actual Oregon ROE for that year is at least 100 basis points above Idaho Power's last authorized Oregon ROE. Oregon jurisdiction power supply cost changes under the APCU and PCAM during 2018 and 2017 did not have a material impact on the companies' financial statements.

Notable Idaho Regulatory Matters

Idaho Base Rate Changes: Idaho base rates were most recently established in 2012, and adjusted in 2014, 2017, and 2018. 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 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 PCA rate that became effective June 1, 2014. In June 2018, the IPUC issued an order adjusting base rates for the impacts of income tax reform, as discussed below in "Income Tax Reform - Regulatory Treatment."

October 2014 Idaho Earnings Support and Sharing Settlement Stipulation: In October 2014, the IPUC issued an order approving an extension, with modifications, of the terms of a 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 accumulated deferred investment tax credits (ADITC) contemplated by the settlement stipulation has been amortized (October 2014 Idaho Earnings Support and Sharing Settlement Stipulation). The provisions of the October 2014 Idaho Earnings Support and Sharing Settlement Stipulation are described in the table included under "Income Tax Reform - Regulatory Treatment" below.

In 2018, Idaho Power recorded a $5.0 million provision against current revenue for sharing with customers, as its full-year return on year-end equity in the Idaho jurisdiction (Idaho ROE) for 2018 was above 10.0 percent. In 2017, Idaho Power did not record any additional ADITC amortization or any provision for sharing with customers, as its Idaho ROE in both years was between 9.5 percent and 10.0 percent. Accordingly, at December 31, 2018, the full $45 million of additional ADITC remains available for future use under the terms of the October 2014 Idaho Earnings Support and Sharing Settlement Stipulation. The October 2014 Idaho Earning Support and Sharing Settlement Stipulation was modified and indefinitely extended, as described in "Income Tax Reform - Regulatory Treatment" below.

Income Tax Reform - Regulatory Treatment: In December 2017, the Tax Cuts and Jobs Act was signed into law, which, among other things, lowered the corporate federal income tax rate from 35 percent to 21 percent and modified or eliminated certain federal income tax deductions for corporations. In March 2018, Idaho House Bill 463 was signed into law reducing the Idaho state corporate income tax rate from 7.4 percent to 6.925 percent.

In January 2018, the IPUC issued an order requiring utilities within its jurisdiction, including Idaho Power, to file a report with the IPUC, identifying and quantifying the financial impact of the income tax reform changes on the utility, along with proposed tariff schedule changes that would adjust the utility's rates and corresponding revenues to reflect the utility's modified federal tax obligations under the Tax Cuts and Jobs Act. The IPUC order required Idaho Power to estimate the income tax reform changes by comparing actual 2017 federal income tax components with what those federal income tax components would have been if the Tax Cuts and Jobs Act had been effective for the full-year 2017.

In March 2018, Idaho Power made a filing with the IPUC providing the results of its pro forma analysis indicating pro forma annual income tax reform expense reductions, composed of a current income tax expense reduction and a deferred income tax expense reduction. In May 2018, the IPUC issued an order approving a settlement stipulation (May 2018 Idaho Tax Reform Settlement Stipulation) related to income tax reform. Beginning June 1, 2018, the settlement stipulation provides an annual (a) $18.7 million reduction to Idaho customer base rates and (b) $7.4 million amortization of existing regulatory deferrals for specified items or future amortization of other existing or future unspecified regulatory deferrals that would otherwise be a future liability recoverable from Idaho customers. Additionally, a one-time benefit of a $7.8 million rate reduction is being provided to Idaho customers through the Idaho-jurisdiction power cost adjustment (PCA) mechanism for the period from June 1, 2018 through May 31, 2019, for the income tax reform benefits accrued from January 1, 2018 to May 31, 2018, and the income tax reform benefits related to Idaho Power's OATT rate. The amount provided via the PCA mechanism will decrease to $2.7 million on June 1, 2019, for income tax reform benefits related to Idaho Power's OATT rate and will cease on June 1, 2020, to reflect the impact of a full year of reduced OATT third-party transmission revenues.

The May 2018 Idaho Tax Reform Settlement Stipulation also provides for the indefinite extension, with modifications, of the October 2014 Idaho Earnings Support and Sharing Settlement Stipulation beyond its termination date of December 31, 2019.

The table below summarizes and compares the terms of the October 2014 Idaho Earnings Support and Sharing Settlement Stipulation with the terms in the May 2018 Idaho Tax Reform Settlement Stipulation that will be applicable commencing on January 1, 2020.

October 2014 Idaho Earnings Support and Sharing Settlement Stipulation (Effective through December 31, 2019)	**May 2018 Idaho Tax Reform Settlement Stipulation** (Effective beginning January 1, 2020, with no defined end date)
If Idaho Power's actual annual Idaho ROE in any year is less than 9.5 percent, then Idaho Power may record additional ADITC amortization up to $25 million to help achieve a 9.5 percent Idaho ROE for that year, and may record additional ADITC amortization up to a total of $45 million over the 2015 through 2019 period. If the $45 million of ADITC are completely amortized, the revenue sharing provisions below would no longer be applicable.	If Idaho Power's actual annual Idaho ROE in any year is less than 9.4 percent, then Idaho Power may amortize up to $25 million of additional ADITC to help achieve a 9.4 percent Idaho ROE for that year, so long as the cumulative amount of ADITC used does not exceed $45 million (Idaho Power will have available and may continue to use any unused portion of the $45 million of additional ADITC from the October 2014 Idaho Earnings Support and Sharing Settlement Stipulation); however, Idaho Power may seek approval from the IPUC to replenish the total amount of ADITC it is permitted to amortize. If there are no remaining amounts of ADITC authorized to be amortized, the revenue sharing provisions below would not be applicable until ADITC is replenished.
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 PCA, and 25 percent to Idaho Power.	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 80 percent to Idaho Power's Idaho customers as a rate reduction to be effective at the time of the subsequent year's PCA, and 20 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 PCA, 25 percent to Idaho Power's Idaho customers in the form of a reduction to the pension regulatory asset balancing account (to reduce the amount to be collected in the future from Idaho customers), and 25 percent to Idaho Power.	If 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 55 percent to Idaho Power's Idaho customers as a rate reduction to be effective at the time of the subsequent year's PCA, 25 percent to Idaho Power's Idaho customers in the form of a reduction to the pension regulatory asset balancing account (to reduce the amount to be collected in the future from Idaho customers), and 20 percent to Idaho Power.
In the event the IPUC approves a change to Idaho Power's allowed annual Idaho ROE as part of a general rate case proceeding before December 31, 2019, the Idaho ROE thresholds will be adjusted on a prospective basis as follows: (a) the Idaho ROE under which Idaho Power will be permitted to amortize an additional amount of ADITC will be set at 95 percent of the newly authorized Idaho ROE, (b) sharing with customers on an 75 percent basis as a customer rate reduction will begin at the newly authorized Idaho ROE, and (c) sharing with customers on a 75 percent basis but allocated 50 percent to a rate reduction, and 25 percent to a pension expense deferral regulatory asset, will begin at 105 percent of the newly authorized Idaho ROE.	In the event the IPUC approves a change to Idaho Power's allowed annual Idaho ROE as part of a general rate case proceeding effective on or after January 1, 2020, the Idaho ROE thresholds will be adjusted on a prospective basis as follows: (a) the Idaho ROE under which Idaho Power will be permitted to amortize an additional amount of ADITC will be set at 95 percent of the newly authorized Idaho ROE, (b) sharing with customers on an 80 percent basis as a customer rate reduction will begin at the newly authorized Idaho ROE, and (c) sharing with customers on an 80 percent basis but allocated 55 percent to a rate reduction, and 25 percent to a pension expense deferral regulatory asset, will begin at 105 percent of the newly authorized Idaho ROE.

Neither the October 2014 Idaho Earnings Support and Sharing Settlement Stipulation nor the May 2018 Idaho Tax Reform Settlement Stipulation impose a moratorium on Idaho Power filing a general rate case or other form of rate proceeding in Idaho during their respective terms.

Also in May 2018, the Public Utility Commission of Oregon (OPUC) issued an order approving a settlement stipulation that provides for an annual $1.5 million reduction to Oregon customer base rates beginning June 1, 2018, through May 31, 2020, related to income tax reform. Unless earlier resolved in a regulatory proceeding, the settlement stipulation requires Idaho Power to file a deferral request with the OPUC by December 31, 2019, to begin tracking income tax reform benefits beginning January 1, 2020, at which time Idaho Power, the OPUC staff, and other interested parties will discuss the methodology to quantify potential future income tax reform benefits.

Fixed Cost Adjustment: The Idaho jurisdiction fixed cost adjustment (FCA) mechanism, applicable to Idaho residential and small commercial customers, is designed to remove a portion of 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. Under Idaho Power's current rate design, recovery of a portion of fixed costs is included in the variable kilowatt-hour charge, which may result in over-collection or under-collection of fixed costs. To return over-collection to customers or to collect under-collection from customers, the FCA mechanism allows Idaho Power to accrue, or defer, the difference between the authorized fixed-cost recovery amount per customer and the actual fixed costs per customer recovered by Idaho Power during the year. Any annual increase in the FCA recovery is capped at 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)
2017	June 1, 2018-May 31, 2019	$15.6
2016	June 1, 2017-May 31, 2018	$35.0

Hells Canyon Complex Relicensing Costs Settlement Stipulation: In December 2016, Idaho Power filed an application with the IPUC requesting a determination that Idaho Power's expenditures of $220.8 million through year-end 2015 on relicensing of the HCC were prudently incurred, and thus eligible for inclusion in retail rates in a future regulatory proceeding. In December 2017, Idaho Power filed with the IPUC a settlement stipulation signed by Idaho Power, the IPUC staff, and a third-party intervenor, recognizing that a total of $216.5 million in HCC relicensing expenditures and other related costs were reasonably incurred, and therefore should be eligible for inclusion in customer rates at a later date. As a result of filing the settlement stipulation, Idaho Power recorded a $5.0 million pre-tax charge in the fourth quarter of 2017, which included $4.3 million for costs incurred through 2015, as well as $0.7 million related to associated costs incurred in 2016 and 2017. Of the $5.0 million pre-tax charge in 2017, $2.5 million was recorded as other operations and maintenance (O&M) expense and $2.5 million was recorded as a reduction to AFUDC. In April 2018, the IPUC issued an order approving the settlement stipulation as filed with the IPUC and determined the $216.5 million of associated costs to be reasonably and prudently incurred.

Western Energy Imbalance Market Costs: Idaho Power's participation in the energy imbalance market implemented in the western United States (Western EIM) commenced on April 4, 2018. The Western EIM aims to reduce the power supply costs to serve customers through more efficient dispatch within the hour of a larger and more diverse pool of resources, to integrate intermittent power from renewable generation sources more effectively, and to enhance reliability.

In January 2017, in response to Idaho Power's request to match costs with benefits of Western EIM participation, the IPUC issued an order authorizing deferral accounting treatment for costs associated with joining the Western EIM. In November 2017, Idaho Power filed an application with the IPUC requesting authorization to establish an interim method of recovery for costs associated with participation in the Western EIM. Through March 2018, Idaho Power had deferred $1.0 million of incremental other O&M costs. In the second quarter of 2018, Idaho Power amortized those costs in accordance with the provisions of the May 2018 Idaho Tax Reform Settlement Stipulation discussed above. In July 2018, the IPUC issued an order approving a settlement stipulation that provides for recovery of ongoing Western EIM-related costs through Idaho Power's PCA mechanism, beginning April 2018. The recovery mechanism provides for monthly incremental revenue, which includes a return on and return of Western EIM-related capital costs and recovery of ongoing Western EIM operating costs. As of April 1, 2018, Idaho Power ceased deferring incremental Western EIM participation O&M start-up costs, and began recognizing the monthly incremental revenue associated with Western EIM participation. From April through December 2018, Idaho Power recorded $2.2 million as a regulatory asset within the PCA balance per the stipulation in order to match the costs with the benefits of the Western EIM.

Valmy Base Rate Adjustment Settlement Stipulations

In May 2017, the IPUC approved a settlement stipulation allowing accelerated depreciation and cost recovery for Idaho Power's jointly-owned North Valmy coal-fired power plant (Valmy Plant). The settlement stipulation provides for an increase in Idaho jurisdictional revenues of $13.3 million per year, and (1) levelized collections and associated cost recovery through December 2028, (2) accelerated depreciation on unit 1 through 2019 and unit 2 through 2025, (3) Idaho Power to use prudent and commercially reasonable efforts to end its participation in the operation of unit 1 by the end of 2019 and unit 2 by the end of 2025, and (4) a filing no later than December 31, 2019 that would include actual and planned incremental investments in unit 2, including updated financial analysis regarding the lowest costs options for unit 2. The costs intended to be recovered by the increased jurisdictional revenues include current investments as of May 31, 2017, in both units, forecasted unit 1 investments from 2017 through 2019, and forecasted decommissioning costs for unit 1 and unit 2, offset by forecasted operation and maintenance costs savings. The settlement stipulation also provides for the regulatory accrual or deferral of the difference between actual revenue requirements and levelized collections, and provides for the regulatory accrual or deferral of the difference between actual costs incurred (including accelerated depreciation expense on unit 1 through 2019 and unit 2 through 2025) compared with costs permitted to be recovered during the cost recovery period specified in the settlement stipulation (including depreciation expense through 2028). If actual costs incurred differ from forecasted amounts included in the settlement stipulation, collection or refund of any differences would be subject to regulatory approval.

In June 2017, the OPUC also approved a settlement stipulation allowing for accelerated depreciation of units 1 and 2 through December 31, 2025, cost recovery of incremental Valmy Plant investments through May 31, 2017, and forecasted decommissioning costs. The settlement stipulation provides for an increase in the Oregon jurisdictional revenue requirement of $1.1 million, effective July 1, 2017, with yearly adjustments, if warranted. As part of the May 2018 settlement stipulation associated with income tax reform described above, the OPUC also deemed prudent Idaho Power's decision to pursue the end of its participation in coal-fired operations of unit 1 by the end of 2019 and approved Idaho Power's request to recover annual incremental accelerated depreciation relating to unit 1, beginning June 1, 2018, and ending December 31, 2019, resulting in a $2.5 million annualized revenue requirement.

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. In June 2018, the OPUC also issued an order adjusting base rates for the impacts of income tax reform, as discussed above in "Income Tax Reform - Regulatory Treatment."

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, 2018 to September 30, 2019	$ 31.25
October 1, 2017 to September 30, 2018	$ 34.90
October 1, 2016 to September 30, 2017	$ 25.52

Idaho Power's current OATT rate is based on a net annual transmission revenue requirement of $123.1 million, which represents the OATT formulaic determination of Idaho Power's net cost of providing OATT-based transmission service.

4. REVENUES

On January 1, 2018, Idaho Power adopted ASU 2014-09, *Revenue from Contracts with Customers,* using the modified retrospective method. The adoption did not change the timing or amounts of revenue recognized by Idaho Power and, therefore, the companies recorded no cumulative-effect adjustment. The following table provides a summary of electric utility operating revenues for Idaho Power (in thousands):

	2018	2017
Electric utility operating revenues:		
Revenue from contracts with customers	$ 1,312,112	$ 1,320,004
Alternative revenue programs and other revenues	54,470	24,889
Total electric utility operating revenues	$ 1,366,582	$ 1,344,893

Revenues from Contracts with Customers

Revenues from contracts with customers are primarily related to Idaho Power's regulated tariff-based sales of energy or related services. Generally, tariff-based sales do not involve a written contract, but are classified as revenues from contracts with customers under ASU 2014-09, *Revenue from Contracts with Customers.* Idaho Power assesses revenues on a contract-by-contract basis to determine the nature, amount, timing, and uncertainty, if any, of revenues being recognized. The following table presents revenues from contracts with customers disaggregated by revenue source (in thousands):

	2018	2017
Revenues from contracts with customers:		
Retail revenues:		
Residential (includes $34,625, $17,320 and $29,170, respectively, related to the FCA [(1)])	$ 530,527	$ 552,333
Commercial (includes $1,299, $876 and $1,087, respectively, related to the FCA[(1)])	310,299	319,195
Industrial	190,130	195,124
Irrigation	158,001	150,030
Provision for sharing	(5,025)	—
Deferred revenue related to HCC relicensing AFUDC[(2)]	(8,780)	(10,706)
Total retail revenues	1,175,152	1,205,976
Less: FCA mechanism revenues[(1)]	(35,924)	(18,196)
Wholesale energy sales	52,845	24,790
Transmission wheeling revenues	59,094	43,970
Energy efficiency program revenues	35,703	39,241
Other revenues from contracts with customers	25,242	24,223
Total revenues from contracts with customers	$ 1,312,112	$ 1,320,004

1) The FCA mechanism is an alternative revenue program in the Idaho jurisdiction and does not represent revenue from contracts with customers.
2) As part of its January 30, 2009, general rate case order, the IPUC is allowing Idaho Power to recover a portion of the AFUDC on construction work in progress related to the HCC relicensing process, even though the relicensing process is not yet complete and the costs have not been moved to electric plant in service. Idaho Power is collecting $8.8 million annually in the Idaho jurisdiction but is deferring revenue recognition of the amounts collected until the license is issued and the accumulated license costs approved for recovery are placed in service. Prior to the May 2018 Idaho Tax Reform Settlement Stipulation described in Note 3 - "Regulatory Matters," Idaho Power was collecting $10.7 million annually.

Retail Revenues: Idaho Power's retail revenues primarily relate to the sale of electricity to customers based on regulated tariff-based prices. Idaho Power recognizes retail revenues in amounts for which it has the right to invoice the customer in the period when energy is delivered or services are provided to customers. The total energy price generally has a fixed component related to having service available and a usage-based component related to the demand, delivery, and consumption of energy. The revenues recognized reflect the consideration Idaho Power expects to be entitled to in exchange for energy and services. Retail customers are classified as residential, commercial, industrial, or irrigation. Approximately 95 percent of Idaho Power's retail revenue originates from customers located in Idaho, with the remainder originating from customers located in Oregon. Idaho Power's retail customer rates are based on Idaho Power's cost of service and are determined through general rate case proceedings, settlement stipulations, and other filings with the IPUC and OPUC. Changes in rates and changes in customer demand are typically the primary causes of fluctuations in retail revenue from period to period. The primary influences on changes in customer demand for electricity are weather, economic conditions (including growth in the number of Idaho Power customers), and energy efficiency. Idaho Power's utility revenues are not earned evenly during the year.

Retail revenues are billed monthly based on meter readings taken throughout the month. Payments for amounts billed are generally due from the customer within 15 days of billing. Idaho Power accrues estimated unbilled revenues for energy or related services delivered to customers but not yet billed at period-end based on actual meter readings at period-end and estimated rates.

Credit losses recorded on receivables arising from Idaho Power's contracts with customers were $3.6 million and $4.7 million for 2018 and 2017, respectively.

Residential Customers: Idaho Power's energy sales to residential customers typically peak during the winter heating season and summer cooling season. Extreme temperatures increase sales to residential customers who use electricity for cooling and heating, compared with normal temperatures. Idaho Power's rate structure provides for higher rates during the summer when overall 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 the seasonal fluctuations in revenues and earnings. Economic and demographic conditions can also affect residential customer demand; strong job growth and population growth in Idaho Power's service area have led to increasing customer growth rates in recent years. Residential demand is also impacted by energy efficiency initiatives. Idaho Power's FCA mechanism mitigates some of the fluctuations caused by weather and energy efficiency initiatives.

Commercial Customers: Most businesses are included in Idaho Power's commercial customer class, as well as small industrial companies, and public street and highway lighting accounts. Idaho Power's commercial customers are less influenced by weather conditions than residential customers, although weather does affect commercial customer energy use. Economic conditions, including manufacturing activity levels, and energy efficiency initiatives also affect energy use of commercial customers.

Industrial Customers: Industrial customers consist of large industrial companies, including special contract customers. Energy use of industrial customers is primarily driven by economic conditions, with weather having little impact on this customer class.

Irrigation Customers: Irrigation customers use electricity to operate irrigation pumps, primarily during the agricultural growing season. The amount and timing of precipitation as well as temperature levels can affect the timing and amounts of sales to irrigation customers, with increased precipitation generally resulting in decreased sales.

Provision for Sharing: Idaho Power's sharing mechanism is associated with the October 2014 Idaho Earnings Support and Sharing Settlement Stipulation that provides for the sharing with customers of a portion of Idaho-jurisdiction earnings exceeding a 10.0 percent Idaho ROE. Based on full-year 2018 Idaho ROE, Idaho Power recorded a $5.0 million provision against current revenues for sharing of earnings with customers for 2018. During 2017, Idaho Power recorded no sharing of earnings with customers. The October 2014 Idaho Earnings Support and Sharing Settlement Stipulation is described further in Note 3 - "Regulatory Matters."

Wholesale Energy Sales: As a public utility under the Federal Power Act (FPA), Idaho Power has the authority to charge market-based rates for wholesale energy sales under its FERC tariff. Idaho Power's wholesale electricity sales are primarily to utilities and power marketers and are predominantly short-term and consist of a single performance obligation satisfied as energy is transferred to the counterparty. Idaho Power's wholesale energy sales depend largely on the availability of generation resources in excess of the amount necessary to serve customer loads as well as adequate market power prices at the time when those resources are available. A reduction in either factor may lead to lower wholesale energy sales.

Transmission Wheeling Revenues: As a public utility under the FPA, Idaho Power has the authority to provide cost-based wholesale and retail access transmission services under its OATT. Services under the OATT are offered on a nondiscriminatory basis such that all potential customers have an equal opportunity to access the transmission system. Idaho Power's transmission revenue is primarily related to third parties reserving capacity on Idaho Power's transmission system to transmit electricity through Idaho Power's service area. The reservations are predominantly short-term but may be part of a long-term capacity contract, short-term contract, or on-demand when available. Transmission wheeling revenues consist of a single performance obligation satisfied as capacity on Idaho Power's transmission system is provided to the third party. Transmission wheeling revenues are affected by changes in Idaho Power's OATT rate and customer demand. Demand for transmission services can be affected by regional market factors, such as loads and generation of utilities in Idaho Power's region.

Energy Efficiency Program Revenues: Idaho Power collects most of its energy efficiency program costs through an energy efficiency rider on customer bills. The rider collections are deferred until expenditures are incurred. Energy efficiency program expenditures funded through the rider are reported as an operating expense with an equal amount recorded in revenues, resulting in no net impact on earnings. Energy efficiency program revenues are recognized in the period when the related costs of the energy efficiency program are incurred by Idaho Power. The cumulative variance between expenditures and amounts collected through the rider is recorded as a regulatory asset or liability. A liability balance indicates that Idaho Power has collected more than it has spent, and an asset balance indicates that Idaho Power has spent more than it has collected. At December 31, 2018, Idaho Power's energy efficiency rider balances were a $5.3 million regulatory liability in the Idaho jurisdiction and a $1.4 million regulatory asset in the Oregon jurisdiction.

Alternative Revenue Programs and Other Revenues

While revenues from contracts with customers make up most of Idaho Power's revenues, the IPUC has authorized the use of the FCA mechanism, which may increase or decrease tariff-based rates billed to customers. The FCA mechanism is described in detail in Note 3 - "Regulatory Matters." The FCA mechanism revenues include only the initial recognition of FCA revenues when the regulator-specified conditions for recognition have been met. Revenue from contracts with customers excludes the portion of the tariff price representing FCA revenues that had been initially recorded in prior periods when regulator-specified conditions were met. When those amounts are included in the price of utility service and billed to customers, such amounts are recorded as recovery of the associated regulatory asset or liability and not as revenues.

The table below presents the FCA mechanism revenues and other revenues (in thousands):

	2018	2017
Alternative revenue programs and other revenues:		
FCA mechanism revenues	$ 35,924	18,196
Derivative revenues	18,546	6,693
Total alternative revenue programs and other revenues	$ 54,470	$ 24,889

5. LONG-TERM DEBT

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

	2018	2017
First mortgage bonds:		
4.50% Series due 2020	$ —	$ 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
6.00% 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	250,000
4.05% Series due 2046	120,000	120,000
4.20% Series due 2048	220,000	—
Total first mortgage bonds	1,665,000	1,575,000
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
Unamortized discounts	(4,598)	(4,125)
Total Idaho Power outstanding debt (2)	1,850,747	1,761,220

(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, 2018, to $1.831 billion.

(2) At December 31, 2018 and 2017, the overall effective cost rate of Idaho Power's outstanding debt was 4.83 percent and 4.87 percent, respectively.

At December 31, 2018, the maturities for the aggregate amount of Idaho Power long-term debt outstanding were as follows (in thousands of dollars):

2019	2020	2021	2022	2023	Thereafter
$ —	$ 100,000	$ —	$ 75,000	$ 75,000	$ 1,605,345

Long-Term Debt Issuances, Maturities, and Availability

In March 2018, Idaho Power issued $220 million in principal amount of 4.20% first mortgage bonds, secured medium-term notes, Series K, maturing on March 1, 2048. In April 2018, Idaho Power redeemed, prior to maturity, $130 million in principal amount of 4.50% first mortgage bonds, medium-term notes, Series H, due March 2020. In accordance with the redemption provisions of the notes, the redemption included Idaho Power's payment of a make-whole premium of $4.6 million. Idaho Power used a portion of the net proceeds of the March 2018 sale of first mortgage bonds, medium-term notes to effect the redemption.

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 and May 2016, 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 is effective through May 31, 2019, subject to extensions upon request to the IPUC. The OPUC's and WPSC's orders do not impose a time limitation for issuances, but the OPUC order does impose a number of other conditions, including a requirement that the interest rates for the debt securities or first mortgage bonds fall within either (a) designated spreads over comparable U.S. Treasury rates or (b) a maximum all-in interest rate limit of 7.0 percent.

On September 27, 2016, Idaho Power entered into a selling agency agreement with seven banks 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 K (Series K Notes), under Idaho Power's Indenture of Mortgage and Deed of Trust, dated as of October 1, 1937, as amended and supplemented (Indenture). At the same time, Idaho Power entered into the Forty-eighth Supplemental Indenture, dated as of September 1, 2016, to the Indenture. The Forty-eighth Supplemental Indenture provides for, among other items, the issuance of up to $500 million in aggregate principal amount of Series K Notes pursuant to the Indenture. As of December 31, 2018, $280 million in principal amount of Series K Notes remained available for issuance under 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.

The Forty-eighth Supplemental Indenture increased the maximum amount of first mortgage bonds issuable by Idaho Power under the Indenture from $2.0 billion to $2.5 billion. Idaho Power may amend the Indenture and increase this amount without consent of the holders of the first mortgage bonds. The amount issuable is also restricted by property, earnings, and other provisions of the Indenture and supplemental indentures to the Indenture. 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.

As of December 31, 2018, Idaho Power could issue under its Indenture approximately $1.9 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 Forty-eighth Supplemental Indenture. As a result, the maximum amount of first mortgage bonds Idaho Power could issue as of December 31, 2018 was limited to approximately $669 million under the Indenture.

6. 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 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 margin is based on Idaho Power's senior unsecured long-term indebtedness credit rating by Moody's Investors Service, Inc., Standard and Poor's Ratings Services, and Fitch Rating Services, Inc., as set forth on a schedule to the credit agreements. Under the credit facility, Idaho Power pays a facility fee on the commitment based on the company's credit rating for senior unsecured long-term debt securities. While the credit facilities provide for an original maturity date of November 6, 2020, the credit agreements grant Idaho Power the right to request up to two one-year extensions, subject to certain conditions. On November 7, 2017 Idaho Power executed the second extension agreement with the consent of all the lenders, extending the maturity date under both credit agreements to November 4, 2022. No other terms of the credit facilities, included the amount of permitted borrowing under the credit agreements, were affected by the extensions.

At December 31, 2018, no loans were outstanding under Idaho Power's facilities. At December 31, 2018, Idaho Power had regulatory authority to incur up to $450 million in principal amount of short-term indebtedness at any one time outstanding. Balances (in thousands of dollars) and interest rates of Idaho Power's short-term borrowings were as follows at December 31, 2018 and 2017:

	2018	2017
Commercial paper balances:		
At the end of year	$ —	$ —
Average during the year	$ —	$ 839
Weighted-average interest rate		
At the end of the year	—%	—%

7. COMMON STOCK

Idaho Power Common Stock

No contributions were made to Idaho Power in 2018 or 2017 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 its credit facility or Idaho Power's Revised Code of Conduct. A covenant under Idaho Power's credit facility requires 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, 2018, the leverage ratio for Idaho Power was 46 percent. Based on these restrictions, Idaho Power's dividends were limited to $1.2 billion at December 31, 2018. 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 Idaho Power from any material subsidiary. At December 31, 2018, 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, 2018, Idaho Power's common equity capital was 54 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 FPA prohibits the payment of dividends from "capital accounts." The term "capital account" is undefined in the FPA 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.

8. SHARE-BASED COMPENSATION

Through its parent company IDACORP, Idaho Power has one share-based compensation plan — the 2000 Long-Term Incentive and Compensation Plan (LTICP). The LTICP (for officers, key employees, and directors) permits the grant of stock options, restricted stock and restricted stock units (together, Restricted Stock), performance shares and performance-based units (together, Performance-Based Shares), and several other types of share-based awards. At December 31, 2018, the maximum number of shares available under the LTICP was 720,408.

Restricted Stock and Performance-Based Shares Awards

Restricted Stock awards have three-year vesting periods and entitle the recipients to dividends or dividend equivalents, as applicable, and voting rights, except that holders of restricted stock units do not have voting rights until the units are vested and settled in shares. Unvested awards 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, reduced for any forfeitures during the vesting period.

Performance-Based Shares awards have three-year vesting periods and entitle the recipients to voting rights, except that holders of performance-based units do not have voting rights until the units are vested and settled in shares. Unvested awards 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 200 percent of the target award. Dividends or dividend equivalents, as applicable, 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 estimated achievement of performance targets, reduced for any forfeitures during the vesting period. 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-Based Shares award activity is presented below. Share amounts represent the shares of IDACORP common stock:

	Number of Shares/Units	Weighted-Average Grant Date Fair Value
Nonvested shares/units at January 1, 2018	199,652	$ 72.39
Shares/units granted	106,402	79.29
Shares/units forfeited	(5,179)	85.07
Shares/units vested	(96,016)	60.31
Nonvested shares/units at December 31, 2018	204,859	$ 81.31

The total fair value of shares vested was $8.3 million in 2018 and $7.5 million in 2017. At December 31, 2018, Idaho Power had $7.9 million of total unrecognized compensation cost related to nonvested share-based compensation. These costs are expected to be recognized over a weighted-average period of 1.7 years. Original issue and/or treasury shares of IDACORP are used for these awards.

In 2018, a total of 12,950 shares of IDACORP common stock were awarded to directors of IDACORP and Idaho Power at a grant date fair value of $81.05 per share. Directors elected to defer receipt of 3,237 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 Idaho Power's compensation cost recognized in income and the tax benefits resulting from the LTICP (in thousands of dollars):

	2018	2017
Compensation cost	$ 9,276	$ 7,304
Income tax benefit (1)	2,388	2,856

(1) Due to the Tax Cuts and Jobs Act, the effective income tax rate was reduced in 2018 for both IDACORP and Idaho Power, which is described in Note 2 - "Income Taxes."

No equity compensation costs have been capitalized. These costs are primarily reported within "Other operations and maintenance" expense on the consolidated statements of income.

9. COMMITMENTS

Purchase Obligations

At December 31, 2018, Idaho Power had the following long-term commitments relating to purchases of energy, capacity, transmission rights, and fuel (in thousands of dollars):

	2019	2020	2021	2022	2023	Thereafter
Cogeneration and power production	$ 238,748	$ 242,206	$ 248,258	$ 251,216	$ 256,403	$ 2,805,159
Fuel	43,163	29,121	28,010	8,389	8,379	84,182

As of December 31, 2018, Idaho Power had 1,119 MW nameplate capacity of PURPA-related projects on-line, with an additional 29 MW nameplate capacity of projects projected to be on-line in 2019. 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 $190 million in 2018 and $170 million in 2017.

Idaho Power also has the following long-term commitments (in thousands of dollars):

	2019	2020	2021	2022	2023	Thereafter
Joint-operating agreement payments (1)	$ 2,902	$ 2,902	$ 2,902	$ 2,902	$ 2,902	$ 14,512
Easements and other payments	240	1,321	1,321	1,331	1,328	16,831
Maintenance and service agreements (1)	34,089	15,694	10,739	11,713	4,140	54,927
FERC and other industry-related fees (1)	14,277	12,714	12,714	12,714	12,714	63,568

(1) Approximately $29 million, $20 million, and $71 million of the obligations included in joint-operating agreement payments, maintenance and service agreements, and FERC and other industry-related fees, respectively, have contracts that do not specify terms related to expiration. As these contracts are presumed to continue indefinitely, ten years of information, estimated based on current contract terms, has been included in the table for presentation purposes.

Idaho Power's expense for operating leases was not material for the years ended 2018 and 2017.

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 (WDEQ), was $58.4 million at December 31, 2018, representing IERCo's one-third share of BCC's total reclamation obligation of $175.2 million. BCC has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. At December 31, 2018, the value of the reclamation trust fund was $101.9 million. During 2018, the reclamation trust fund made distributions of $6.7 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, and does, add a per-ton surcharge to coal sales, all of which are made to the Jim Bridger plant. 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 its historical experience and the evaluation of the specific indemnities. As of December 31, 2018, 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 sheets with respect to these indemnification obligations.

10. CONTINGENCIES

Idaho Power has in the past and expect in the future to become involved in various claims, controversies, disputes, and other contingent matters, some of which 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, as applicable, 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. 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 its 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, although there is no assurance that such recovery would be granted.

Idaho Power is party to legal claims and legal and regulatory actions and proceedings in the ordinary course of business and, as noted above, records an accrual for associated loss contingencies when they are probable and reasonably estimable. In connection with its utility operations, Idaho Power is subject to claims by individuals, entities, and governmental agencies for damages for alleged personal injury, property damage, and economic losses, relating to the company's provision of electric service and the operation of its generation, transmission, and distribution facilities. Some of those claims relate to electrical contacts, service quality, property damage, and wildfires. In recent years, utilities in the western United States have been subject to significant liability for personal injury, loss of life, property damage, trespass, and economic losses, and in some cases, punitive damages and criminal charges, associated with wildfires that originated from utility property, most commonly transmission and distribution lines. In recent years, Idaho Power has regularly received claims by both governmental agencies and private landowners for damages for fires allegedly originating from Idaho Power's transmission and distribution system. As of the date of this report, the companies believe that resolution of existing claims will not have a material adverse effect on their respective consolidated financial statements. Idaho Power is also actively monitoring various pending environmental regulations and executive orders related to environmental matters 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.

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 two nonqualified defined benefit pension plans for certain senior management employees called the Security Plan for Senior Management Employees I and Security Plan for Senior Management Employees II (together, 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 2018 and 2017, 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	
	2018	**2017**	**2018**	**2017**
Change in projected benefit obligation:				
Benefit obligation at January 1	$ 999,344	$ 895,060	$ 110,303	$ 99,570
Service cost	37,836	33,742	(316)	759
Interest cost	38,833	38,957	4,248	4,315
Actuarial (gain) loss	(84,758)	67,758	(7,050)	10,635
Benefits paid	(39,398)	(36,173)	(4,867)	(4,976)
Projected benefit obligation at December 31	951,857	999,344	102,318	110,303
Change in plan assets:				
Fair value at January 1	697,683	607,568	—	—
Actual (loss) return on plan assets	(47,681)	86,288	—	—
Employer contributions	40,000	40,000	—	—
Benefits paid	(39,398)	(36,173)	—	—
Fair value at December 31	650,604	697,683	—	—
Funded status at end of year	$ (301,253)	$ (301,661)	$ (102,318)	$ (110,303)
Amounts recognized in the statement of financial position consist of:				
Other current liabilities	$ —	$ —	$ (5,158)	$ (5,010)
Noncurrent liabilities	(301,253)	(301,661)	(97,160)	(105,293)
Net amount recognized	$ (301,253)	$ (301,661)	$ (102,318)	$ (110,303)
Amounts recognized in accumulated other comprehensive income consist of:				
Net loss	$ 278,720	$ 277,052	$ 30,496	$ 41,333
Prior service cost	62	68	399	498
Subtotal	278,782	277,120	30,895	41,831
Less amount recorded as regulatory asset	(278,782)	(277,120)	—	—
Net amount recognized in accumulated other comprehensive income	$ —	$ —	$ 30,895	$ 41,831
Accumulated benefit obligation	$ 814,549	$ 850,763	$ 94,630	$ 100,222

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 $92.5 million and $85.7 million at December 31, 2018 and 2017, 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	
	2018	2017	2018	2017
Service cost	$ 37,836	$ 33,742	$ (316)	$ 759
Interest cost	38,833	38,957	4,248	4,315
Expected return on assets	(52,302)	(45,138)	—	—
Amortization of net loss	13,558	13,190	3,788	2,963
Amortization of prior service cost	6	28	98	127
Net periodic pension cost	37,931	40,779	7,818	8,164
Regulatory deferral of net periodic benefit cost (1)	(36,153)	(38,699)	—	—
Previously deferred pension cost recognized (1)	17,154	17,154	—	—
Net periodic benefit cost recognized for financial reporting (1)(2)	$ 18,932	$ 19,234	$ 7,818	$ 8,164

(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, the Idaho portion of net periodic benefit cost is recorded as a regulatory asset and is recognized in the income statement as those costs are recovered through rates.

(2) Of total net periodic benefit cost recognized for financial reporting $15.2 million and $16.2 million, respectively, was recognized in "Other operations and maintenance" and $11.6 million and $11.2 million, respectively, was recognized in "Other expense, net" on the consolidated statements of income of the companies for the twelve months ended December 31, 2018 and 2017.

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

	Pension Plan		SMSP	
	2018	2017	2018	2017
Actuarial (loss) gain during the year	$ (15,226)	$ (26,608)	$ 7,049	$ (10,635)
Plan amendment service cost	—	—	—	—
Reclassification adjustments for:				
Amortization of net loss	13,558	13,190	3,788	2,963
Amortization of prior service cost	6	28	98	127
Adjustment for deferred tax effects	428	1,744	(2,815)	1,555
Adjustment due to the effects of regulation	1,234	11,646	—	—
Other comprehensive income recognized related to pension benefit plans	$ —	$ —	$ 8,120	$ (5,990)

In 2019, Idaho Power expects to recognize as components of net periodic benefit cost $16.5 million from amortizing amounts recorded in accumulated other comprehensive income (or as a regulatory asset for the pension plan) as of December 31, 2018, relating to the pension plan and SMSP. This amount consists of $13.9 million of amortization of net loss for the pension plan and $2.5 million of amortization of net loss and $0.1 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):

	2019	2020	2021	2022	2023	2024-2028
Pension Plan	$ 38,177	$ 40,287	$ 42,403	$ 44,489	$ 46,671	$ 264,707
SMSP	5,266	5,716	5,901	6,071	6,431	31,867

As of December 31, 2018, Idaho Power's minimum required contributions to the pension plan are estimated to be zero in 2019. Depending on market conditions and cash flow considerations in 2019, Idaho Power could contribute up to $40 million to the pension plan during 2019 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):

	2018	2017
Change in accumulated benefit obligation:		
Benefit obligation at January 1	$ 70,051	$ 63,876
Service cost	1,051	973
Interest cost	2,643	2,783
Actuarial (gain) loss	(2,688)	5,769
Benefits paid (1)	(4,604)	(3,562)
Plan amendments	—	212
Benefit obligation at December 31	66,453	70,051
Change in plan assets:		
Fair value of plan assets at January 1	38,294	34,999
Actual (loss) return on plan assets	(1,330)	5,112
Employer contributions (1)	1,031	1,745
Benefits paid (1)	(4,604)	(3,562)
Fair value of plan assets at December 31	33,391	38,294
Funded status at end of year (included in noncurrent liabilities)	$ (33,062)	$ (31,757)

(1) Contributions and benefits paid are each net of $3.1 million and $3.4 million of plan participant contributions for 2018 and 2017, respectively.

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

	2018	2017
Net (loss) gain	$ (330)	$ 2,777
Prior service cost	222	269
Subtotal	(108)	3,046
Less amount recognized in regulatory assets	108	(3,046)
Net amount recognized in accumulated other comprehensive income	$ —	$ —

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

	2018	2017
Service cost	$ 1,051	$ 973
Interest cost	2,643	2,783
Expected return on plan assets	(2,467)	(2,307)
Immediate recognition of loss from temporary deviation (1)	4,216	—
Amortization of prior service cost	47	47
Net periodic postretirement benefit cost	$ 5,490	$ 1,496

(1) In 2018, a loss associated with a temporary deviation from the cost-sharing provisions of the substantive plan was recognized in "Other expense, net" on the consolidated statements of income of the companies.

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

	2018	2017
Actuarial loss during the year	$ (1,109)	$ (2,964)
Prior service cost arising during the year	—	(212)
Reclassification adjustments for:		
Immediate recognition of loss from temporary deviation (1)	4,216	—
Reclassification adjustments for amortization of prior service cost	47	47
Adjustment for deferred tax effects	270	807
Adjustment due to the effects of regulation	(3,424)	2,322
Other comprehensive income related to postretirement benefit plans	$ —	$ —

(1) In 2018, a loss associated with a temporary deviation from the cost-sharing provisions of the substantive plan was recognized in "Other expense, net" on the consolidated statements of income of the companies.

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

	2019	2020	2021	2022	2023	2024-2028
Expected benefit payments	$ 5,438	$ 5,051	$ 4,894	$ 4,732	$ 4,549	$ 20,080

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	
	2018	2017	2018	2017	2018	2017
Discount rate	4.55%	3.95%	4.60%	3.95%	4.60%	3.95%
Rate of compensation increase [1]	4.25%	4.17%	4.75%	4.75%	—	—
Medical trend rate	—	—	—	—	6.3%	6.8%
Dental trend rate	—	—	—	—	4.0%	4.0%
Measurement date	12/31/2018	12/31/2017	12/31/2018	12/31/2017	12/31/2018	12/31/2017

(1) The 2018 rate of compensation increase assumption for the pension plan includes an inflation component of 2.50% plus a 1.75% 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	
	2018	2017	2018	2017	2018	2017
Discount rate	3.95%	4.45%	3.95%	4.45%	3.95%	4.45%
Expected long-term rate of return on assets	7.50%	7.50%	—	—	6.75%	6.75%
Rate of compensation increase	4.25%	4.17%	4.75%	4.75%	—	—%
Medical trend rate	—	—	—	—	6.3%	6.8%
Dental trend rate	—	—	—	—	4.0%	4.0%

The assumed health care cost trend rate used to measure the expected cost of health benefits covered by the postretirement plan was 6.3 percent in 2018 and is assumed to decrease to 5.7 percent in 2019, 5.1 percent in 2020, 5.1 percent in 2021 and to gradually decrease to 4.1 percent by 2076. The assumed dental cost trend rate used to measure the expected cost of dental benefits covered by the plan was 4.0 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, 2018 (in thousands of dollars):

	One-Percentage-Point	
	Increase	Decrease
Effect on total of cost components	$ 339	$ (247)
Effect on accumulated postretirement benefit obligation	3,222	(2,483)

Plan Assets

Pension Asset Allocation Policy: The target allocation and actual allocations at December 31, 2018, for the pension asset portfolio by asset class is set forth below:

Asset Class	Target Allocation	Actual Allocation December 31, 2018
Debt securities	24%	26%
Equity securities	56%	56%
Real estate	7%	6%
Other plan assets	13%	12%
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 plan participants.

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 approximately 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, 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 - "Fair Value Measurements." The following table presents the fair value of the plans' investments by asset category (in thousands of dollars).

	Level 1	Level 2	Level 3	Total
Assets at December 31, 2018				
Cash and cash equivalents	$ 9,717	$ —	$ —	$ 9,717
Short-term bonds	20,644	—	—	20,644
Intermediate bonds	20,595	87,646	—	108,241
Long-term bonds	—	40,857	—	40,857
Equity Securities: Large-Cap	71,176	—	—	71,176
Equity Securities: Mid-Cap	71,419	—	—	71,419
Equity Securities: Small-Cap	53,401	—	—	53,401
Equity Securities: Micro-Cap	30,387	—	—	30,387
Equity Securities: International	7,104	—	—	7,104
Equity Securities: Emerging Markets	6,519	—	—	6,519
Plan assets measured at NAV (not subject to hierarchy disclosure)				
Equity Securities: Global and International				95,653
Equity Securities: Emerging Markets				29,757
Real estate				39,846
Private market investments				35,041
Commodities fund				30,842
Total	$ 290,962	$ 128,503	$ —	$ 650,604
Postretirement plan assets [1]	$ 758	$ 32,633	$ —	$ 33,391

	Level 1	Level 2	Level 3	Total
Assets at December 31, 2017				
Cash and cash equivalents	$ 20,852	$ —	$ —	$ 20,852
Short-term bonds	20,475	—	—	20,475
Intermediate bonds	20,699	82,923	—	103,622
Long-term bonds	—	40,707	—	40,707
Equity Securities: Large-Cap	95,179	—	—	95,179
Equity Securities: Mid-Cap	81,127	—	—	81,127
Equity Securities: Small-Cap	62,502	—	—	62,502
Equity Securities: Micro-Cap	32,753	—	—	32,753
Equity Securities: International	6,774	—	—	6,774
Equity Securities: Emerging Markets	8,785	—	—	8,785
Plan assets measured at NAV (not subject to hierarchy disclosure)				
Equity Securities: International				83,589
Equity Securities: Emerging Markets				36,255
Real estate				38,435
Private market investments				31,618
Commodities fund				35,010
Total	$ 349,146	$ 123,630	$ —	$ 697,683
Postretirement plan assets (1)	$ 567	$ 37,727	$ —	$ 38,294

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

For the years ended December 31, 2018 and 2017, there were no material transfers into or out of Levels 1, 2, or 3.

Fair Value Measurement of Level 2 Plan assets and Plan assets measured at NAV:

Level 2 Bonds: These investments represent U.S. government, agency bonds, and corporate bonds. The U.S. government and agency bonds, as well as the corporate bonds, are not traded on an exchange and are valued utilizing market prices for similar assets or liabilities in active markets.

Level 2 Postretirement Asset: This asset represents an investment in a life insurance contract and is 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.

Commingled Funds: These funds, made up of the global, international, emerging markets equity securities, and commodities fund measured at NAV, are not publicly traded, and therefore no publicly quoted market price is readily available. The values of the commingled funds are presented at estimated fair value, which is determined based on the unit value of the fund. The values of these investments are calculated by the custodian for the fund company on a monthly or more frequent basis, and are based on market prices of the assets held by each of the commingled funds divided by the number of fund shares outstanding for the respective fund. The investments in commingled funds have redemption limitations that permit monthly redemption following notice requirements of 5 to 7 days.

Real Estate: Real estate holdings represent investments in 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 companies, 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 real estate funds also furnish annual audited financial statements that are also used to further validate the information provided. Redemptions are generally available on a quarterly basis, with 10 to 35 days written notice, depending on the individual fund. If the fund has sufficient liquidity, the redemption will be processed at the fund NAV or the fund's estimate of fair value at the end of the quarter. If the fund does not have sufficient liquidity to honor the full redemption, the remainder will be set for redemption the following quarter on a pro-rata basis with other redemption requests. This same process will repeat until the redemption request has been completed. To protect other fund holders, real estate funds have no duty to liquidate or encumber funds to meet redemption requests.

Private Market Investments: Private market investments represent two categories: fund of hedge funds and venture capital funds. These funds are valued by the fund companies based on the estimated fair values of the underlying fund holdings divided by the fund shares outstanding or multiplied by the ownership percentages of the holder. 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. Redemptions are available on a quarterly basis with 70 days written notice. Redemptions will be processed at the quarterly NAV or fair value within 60 days following quarter end. In the event of a full redemption, a reserve amount of 5% to 10% of the redemption amount may be held in reserve until the audited financial statements of the fund are published. This allows the fund to adjust the redemption so that other fund holders are not adversely impacted. Venture capital fund investments are valued by the fund companies 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. These funds are formed for a stated life of 10 to 15 years. The general partner can extend the fund life for 2 or 3 one-year periods. The fund can be further extended with the approval of the limited partners. There are generally no redemption rights associated with these funds. The limited partner must hold the fund for the life of the fund or find a third-party buyer.

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 $7.7 million and $7.4 million in 2018 and 2017, respectively.

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 benefits included in other deferred credits on Idaho Power's consolidated balance sheets at December 31, 2018, and 2017, were approximately $2 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 ended December 31, 2018 and 2017 (in thousands of dollars):

	2018		2017	
	Balance	Avg Rate	Balance	Avg Rate
Production	$ 2,654,201	3.10%	$ 2,598,940	3.07%
Transmission	1,201,092	1.89%	1,163,240	1.94%
Distribution	1,792,284	2.24%	1,710,126	2.44%
General and Other	456,279	6.40%	433,856	6.01%
Total in service	6,103,856	2.84%	5,906,162	2.87%
Accumulated provision for depreciation	(2,210,781)		(2,098,274)	
In service - net	$ 3,893,075		$ 3,807,888	

At December 31, 2018, Idaho Power's construction work in progress balance of $480.3 million included relicensing costs of $297.0 million for the HCC, Idaho Power's largest hydroelectric complex. In 2018, 2017, and 2016, the IPUC authorized Idaho Power to include in its Idaho jurisdiction rates $6.5 million annually ($8.8 million when grossed-up for the effect of income taxes in 2018 and $10.7 million when grossed-up for the effect of income taxes in 2017 and 2016 prior to income tax reform described in Note 2 - "Income Taxes") of AFUDC relating to the HCC relicensing project. Collecting these amounts will reduce the amount collected in the future once the HCC relicensing costs are approved for recovery in base rates. At December 31, 2018, Idaho Power's accumulated provision for rate refunds for collection of AFUDC relating to the HCC was $135.1 million.

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, 2018 (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	$ 733,451	$ 5,141	$ 334,731	33	771
Boardman	Boardman, OR	82,459	4	74,748	10	64
Valmy units 1 and 2	Winnemucca, NV	410,947	248	279,643	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 $81.8 million in 2018 and $86.4 million in 2017.

Idaho Power has contracts to purchase the energy from four PURPA qualifying facilities that are 50 percent owned by Ida-West. Idaho Power's power purchases from these facilities were $9.7 million in 2018 and $9.8 million in 2017.

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. Accretion, depreciation, and gains or losses related to the Boardman generating facility are 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.

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):

		2018		2017
Balance at beginning of year	$	26,415	$	26,257
Accretion expense		1,055		1,015
Revisions in estimated cash flows		(751)		(791)
Liability incurred		129		—
Liability settled		(56)		(66)
Balance at end of year	$	26,792	$	26,415

14. INVESTMENTS

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

		2018		2017
Idaho Power investments:				
IERCO	$	57,026	$	72,213
Exchange traded short-term bond funds and cash equivalents		36,471		30,249
Executive deferred compensation plan investments		17		17
Total Idaho Power investments		93,514		102,479

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, 2018 and December 31, 2017. The following table summarizes sales of available-for-sale securities (in thousands of dollars):

		2018		2017		2016
Proceeds from sales	$	5,007	$	4,989	$	15,693
Gross realized gains from sales		—		—		54

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, 2018 and 2017 (in thousands of dollars):

	Location of Realized Gain/(Loss) on Derivatives Recognized in Income	Gain/(Loss) on Derivatives Recognized in Income (1)	
		2018	2017
Financial swaps	Operating revenues	$ 1,316	$ 902
Financial swaps	Purchased power	7,828	166
Financial swaps	Fuel expense	22,563	701
Financial swaps	Other operations and maintenance	118	(84)
Forward contracts	Operating revenues	41	55
Forward contracts	Purchased power	(54)	(69)
Forward contracts	Fuel expense	(186)	4

(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 revenues from contracts with customers 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 - "Fair Value Measurements" 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, 2018 and 2017 (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, 2018							
Current:							
Financial swaps	Other current assets	$ 4,639	$ (984) (1)	$ 3,655	$ 938	$ (938)	$ —
Financial swaps	Other current liabilities	—	—	—	806	—	806
Forward contracts	Other current liabilities	—	—	—	104	—	104
Long-term:							
Financial swaps	Other liabilities	—	—	—	64	—	64
Total		$ 4,639	$ (984)	$ 3,655	$ 1,912	$ (938)	$ 974
December 31, 2017							
Current:							
Financial swaps	Other current assets	$ 18	$ —	$ 18	$ —	$ —	$ —
Financial swaps	Other current liabilities	553	(553)	—	1,971	(748) (2)	1,223
Forward contracts	Other current liabilities	—	—	—	2	—	2
Long-term:							
Financial swaps	Other assets	4	—	4	—	—	—
Total		$ 575	$ (553)	$ 22	$ 1,973	$ (748)	$ 1,225

1) Current asset derivative amounts offset include $45 thousand of collateral payable for the period ending December 31, 2018.
2) Current liability derivative amounts offset include $196 thousand of collateral receivable for the period ending December 31, 2017.

The table below presents the volumes of derivative commodity forward contracts and swaps outstanding at December 31, 2018 and 2017 (in thousands of units):

		December 31,	
Commodity	**Units**	**2018**	**2017**
Electricity purchases	MWh	52	312
Electricity sales	MWh	39	224
Natural gas purchases	MMBtu	7,514	7,028
Natural gas sales	MMBtu	446	140

Credit Risk

At December 31, 2018, 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 WSPP, Inc. 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, 2018, was $1.9 million. Idaho Power posted no cash collateral related to this amount. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2018, Idaho Power would have been required to pay or post collateral to its counterparties up to an additional $7.8 million to cover open liability positions as well as completed transactions that have not yet been paid.

16. 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 have 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, 2018 and 2017.

The following table presents information about Idaho Power's assets and liabilities measured at fair value on a recurring basis as of December 31, 2018 and 2017 (in thousands of dollars):

	December 31, 2018				December 31, 2017			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets:								
Money market funds and commercial paper	$79,228	$—	$—	$79,228	$10,260	$—	$—	$10,260
Derivatives	3,655	—	—	3,655	22	—	—	22
Equity securities	36,488	—	—	36,488	30,266	—	—	30,266
Liabilities:								
Derivatives	$ 870	$ 104	$ —	$ 974	$ 1,223	$ 2	$ —	$ 1,225

(1) Holding company only. Does not include amounts held by Idaho Power.

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 with quoted prices in an active market. Natural gas and diesel derivatives are valued using New York Mercantile Exchange and Intercontinental Exchange pricing, adjusted for location basis, which are also quoted under NYMEX and ICE pricing. Equity securities consist of employee-directed investments related to an executive deferred compensation plan and actively traded money market and exchange traded funds related to the SMSP. The investments are measured using quoted prices in active markets 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, 2018 and 2017, using available market information and appropriate valuation methodologies (in thousands).

	December 31, 2018		December 31, 2017	
	Carrying Amount	Estimated Fair Value	Carrying Amount	Estimated Fair Value
	(thousands of dollars)			
Liabilities:				
Long-term debt (1)	$ 1,834,788	$ 1,942,773	$ 1,746,123	$ 1,915,459

(1) Long-term debt are categorized as Level 3 and Level 2, respectively, of the fair value hierarchy, as defined earlier in this Note 16 - "Fair Value Measurements."

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. CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME

Comprehensive income includes net income 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, 2018 and 2017 (in thousands of dollars). Items in parentheses indicate reductions to AOCI.

	Year Ended December 31,	
	2018	2017
Defined benefit pension items		
Balance at beginning of period	$ (26,872)	$ (20,882)
Other comprehensive income before reclassifications	5,234	(7,872)
Amounts reclassified out of AOCI to net income	2,886	1,882
Net current-period other comprehensive income	8,120	(5,990)
Cumulative effect of change in accounting principle (1)	(4,092)	—
Balance at end of period	$ (22,844)	$ (26,872)

(1) In November 2018, the FERC issued a final accounting order allowing certain entities, including Idaho Power, to make a policy election to reclassify the stranded tax effects resulting from income tax reform from AOCI to retained earnings in accordance with ASU 2018-02, *Income Statement—Reporting Comprehensive Income (Topic 220).* In 2018, Idaho Power transferred $4.1 million from AOCI to retained earnings.

The table below presents the effects on net income of amounts reclassified out of components of AOCI and the income statement location of those amounts reclassified during the years ended December 31, 2018 and 2017 (in thousands of dollars). Items in parentheses indicate increases to net income.

	Amount Reclassified from AOCI	
	Year Ended December 31,	
	2018	2017
Amortization of defined benefit pension items[1]		
Prior service cost	$ 98	$ 127
Net loss	3,788	2,963
Total before tax	3,886	3,090
Tax benefit [2]	(1,000)	(1,208)
Net of tax	2,886	1,882
Total reclassification for the period	$ 2,886	$ 1,882

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

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

18. 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 $0.7 million in both 2018 and 2017.

At December 31, 2018 and 2017, Idaho Power had a $1.9 million and $57.3 million payable to IDACORP, respectively, which was included in its accounts payable to affiliates balance on its consolidated balance sheets. In 2018, Idaho Power paid IDACORP certain estimated income taxes that had been accrued at December 31, 2017.

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 $9.7 million in 2018 and $9.8 million in 2017 for that power.

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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	04/16/2019	End of 2018/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)	6,103,104,829	6,103,104,829
4	Property Under Capital Leases		
5	Plant Purchased or Sold		
6	Completed Construction not Classified		
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	6,103,104,829	6,103,104,829
9	Leased to Others		
10	Held for Future Use	4,751,462	4,751,462
11	Construction Work in Progress	480,258,675	480,258,675
12	Acquisition Adjustments	750,893	750,893
13	Total Utility Plant (8 thru 12)	6,588,865,859	6,588,865,859
14	Accum Prov for Depr, Amort, & Depl	2,394,578,627	2,394,578,627
15	Net Utility Plant (13 less 14)	4,194,287,232	4,194,287,232
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	2,369,301,348	2,369,301,348
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	25,229,722	25,229,722
22	Total In Service (18 thru 21)	2,394,531,070	2,394,531,070
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	47,557	47,557
33	Total Accum Prov (equals 14) (22,26,30,31,32)	2,394,578,627	2,394,578,627

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	30,669,683	2,828,359
4	(303) Miscellaneous Intangible Plant	26,616,961	11,042,574
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	57,292,347	13,870,933
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,722,421	
9	(311) Structures and Improvements	154,463,765	2,107,274
10	(312) Boiler Plant Equipment	757,671,126	12,516,851
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	169,859,625	2,858,191
13	(315) Accessory Electric Equipment	73,750,009	1,064,170
14	(316) Misc. Power Plant Equipment	20,152,814	2,385,775
15	(317) Asset Retirement Costs for Steam Production	14,889,891	-733,146
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	1,192,509,651	20,199,115
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	31,497,639	157,426
28	(331) Structures and Improvements	196,242,642	4,101,160
29	(332) Reservoirs, Dams, and Waterways	273,545,283	2,182,772
30	(333) Water Wheels, Turbines, and Generators	260,309,413	31,719,160
31	(334) Accessory Electric Equipment	62,464,867	2,039,620
32	(335) Misc. Power PLant Equipment	25,991,708	1,090,249
33	(336) Roads, Railroads, and Bridges	10,881,683	1,004,050
34	(337) Asset Retirement Costs for Hydraulic Production		
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	860,933,235	42,294,437
36	D. Other Production Plant		
37	(340) Land and Land Rights	2,690,006	9,788
38	(341) Structures and Improvements	143,332,756	34,376
39	(342) Fuel Holders, Products, and Accessories	10,537,569	177,298
40	(343) Prime Movers	224,537,829	10,259,022
41	(344) Generators	66,531,876	182,172
42	(345) Accessory Electric Equipment	91,478,361	403,449
43	(346) Misc. Power Plant Equipment	6,388,713	102,375
44	(347) Asset Retirement Costs for Other Production		
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	545,497,110	11,168,480
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	2,598,939,996	73,662,032

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
			33,498,042		3
8,631,209			29,028,326		4
8,631,209			62,532,071		5
					6
					7
			1,722,421		8
501,811			156,069,228		9
6,351,836			763,836,141		10
					11
328,089			172,389,727		12
155,844			74,658,335		13
507,310			22,031,279		14
			14,156,745		15
7,844,890			1,204,863,876		16
					17
					18
					19
					20
					21
					22
					23
					24
					25
					26
			31,655,065		27
417,519			199,926,283		28
541,606			275,186,449		29
981,961			291,046,612		30
722,285			63,782,202		31
462,800			26,619,157		32
4,000			11,881,733		33
					34
3,130,171			900,097,501		35
					36
			2,699,794		37
28,341			143,338,791		38
			10,714,867		39
7,352,922			227,443,929		40
			66,714,048		41
44,618			91,837,192		42
			6,491,088		43
					44
7,425,881			549,239,709		45
18,400,942			2,654,201,086		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	04/16/2019	End of 2018/Q4

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

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	37,127,446	1,796,147
49	(352) Structures and Improvements	80,263,617	779,590
50	(353) Station Equipment	428,949,669	14,651,950
51	(354) Towers and Fixtures	206,552,729	4,834,230
52	(355) Poles and Fixtures	183,335,657	14,396,763
53	(356) Overhead Conductors and Devices	226,621,106	8,673,207
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)	1,163,240,490	45,131,887
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	6,052,619	500,666
61	(361) Structures and Improvements	37,463,373	2,929,310
62	(362) Station Equipment	237,332,109	18,934,953
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	265,381,383	9,083,493
65	(365) Overhead Conductors and Devices	136,069,938	6,625,653
66	(366) Underground Conduit	50,759,070	1,932,118
67	(367) Underground Conductors and Devices	258,499,754	20,485,907
68	(368) Line Transformers	560,033,828	35,074,016
69	(369) Services	60,786,068	1,715,228
70	(370) Meters	90,021,168	6,730,337
71	(371) Installations on Customer Premises	3,057,356	120,491
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	4,526,921	112,690
74	(374) Asset Retirement Costs for Distribution Plant	142,630	
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	1,710,126,217	104,244,862
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	17,461,464	282,090
87	(390) Structures and Improvements	120,654,120	7,025,068
88	(391) Office Furniture and Equipment	44,912,532	9,506,697
89	(392) Transportation Equipment	88,148,894	8,314,242
90	(393) Stores Equipment	2,947,647	86,112
91	(394) Tools, Shop and Garage Equipment	10,438,164	800,860
92	(395) Laboratory Equipment	13,869,062	341,551
93	(396) Power Operated Equipment	16,265,279	3,045,899
94	(397) Communication Equipment	54,135,749	1,090,906
95	(398) Miscellaneous Equipment	6,979,100	707,965
96	SUBTOTAL (Enter Total of lines 86 thru 95)	375,812,011	31,201,390
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)	375,812,011	31,201,390
100	TOTAL (Accounts 101 and 106)	5,905,411,061	268,111,104
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)	5,905,411,061	268,111,104

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	04/16/2019	End of 2018/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
56			38,923,537		48
19,413			81,023,794		49
2,575,921			441,025,698		50
29,119			211,357,840		51
2,524,737			195,207,683		52
2,131,230			233,163,083		53
					54
					55
			390,266		56
					57
7,280,476			1,201,091,901		58
					59
			6,553,285		60
108,927			40,283,756		61
1,903,678			254,363,384		62
					63
2,768,978			271,695,898		64
2,210,426			140,485,165		65
453,187			52,238,001		66
3,016,630			275,969,031		67
7,515,663			587,592,181		68
581,568			61,919,728		69
3,424,210			93,327,295		70
53,515			3,124,332		71
					72
50,726			4,588,885		73
			142,630		74
22,087,508			1,792,283,571		75
					76
					77
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					80
					81
					82
					83
					84
					85
			17,743,554		86
160,419			127,518,769		87
5,912,746			48,506,483		88
3,597,458			92,865,678		89
10,654			3,023,105		90
144,160			11,094,864		91
507,083			13,703,530		92
76,867			19,234,311		93
3,297,353			51,929,302		94
310,461			7,376,604		95
14,017,201			392,996,200		96
					97
					98
14,017,201			392,996,200		99
70,417,336			6,103,104,829		100
					101
					102
					103
70,417,336			6,103,104,829		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	04/16/2019	End of 2018/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	2020/2021	480,501
3	Production			109,961
4	Transmission Stations			423,088
5	Transmission Lines			195,489
6	Distribution Stations			1,084,696
7	Beacon Light Substation	12/30/02	2020	465,662
8	Homedale Substation	2/29/08	2035	109,453
9	Line #854 500 Kv	3/31/09	2024	308,066
10	General Plant			62,673
11	Distribution Line			25,581
12				
13				
14	Column B and C if no date listed it is various			
15				
16				
17				
18				
19				
20				
21	Other Property:			
22	Transmission Stations			199,069
23	Distribution Stations			69,941
24	Homedale Substation	2/29/08	2035	217,797
25	Beacon Light Substation	12/30/02	2020	555,940
26	Underground Vault, Blaine County	8/30/16	2021	443,545
27				
28				
29				
30	Column B and C if no date listed it is various			
31				
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46				
47	Total			4,751,462

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	113,511,636
2	ROLLUP RELIC COST HELLS CANYON	77,297,487
3	GATEWAY WEST 500KV LINE	38,052,995
4	ROLLUP RELIC COST OXBOW	35,961,818
5	HELLS CANYON RELICENSING OUTSI	32,424,212
6	B2H PERMITTING 11/1/2011 & FOR	17,638,563
7	BOARDMAN - HEMINGWAY 500 KV LI	9,317,310
8	HCC WATERSHED ENHANCEMENT PROG	8,157,383
9	BROWNLEE UNIT 2 TURBINE REFURB	7,559,022
10	UPPER MALAD FISH LADDER	5,925,263
11	LEGAL DEPT. LABOR FOR RELICENS	5,464,205
12	WQ HCC401 CERTIFICATION OPS AN	5,192,744
13	LANGLEY GULCH WATER BETTERMENT	4,856,493
14	BAYHA ISLAND RESEARCH PROJECT	4,707,424
15	SHOSHONE FALLS UPGRADE - REPLA	4,382,017
16	REL-HCC OREGON REAUTHORIZATION	3,790,834
17	B2H TLINE CONSTRUCTION COSTS	3,162,876
18	METEOROLOGY MODEL FOR OPERATIO	3,116,606
19	BULL TROUT PROGRAM - ADMINISTR	3,049,751
20	BTLR150001 NEW METALCLAD	2,854,365
21	GRAND VIEW IRRIGATION UPGRADE	2,825,728
22	NEWX140005 - NEW 138KV LINE FR	2,702,515
23	WDRI-KCHM NEW 138KV	2,583,099
24	WQ HCC401 APPLICATION, REVISIO	2,421,271
25	FALL CHINOOK PROGRAM - REDD SU	2,342,937
26	700MHZ SPECTRUM PURCHASE	2,202,592
27	HBND-041:ALT LINE ROUTE TO GAR	2,025,580
28	SFP EQUIPMENT SKIP	2,015,864
29	LOWER SALMON UNIT 2 REFURB	1,923,786
30	HCC RELICENSING WATER QUALITY	1,831,430
31	BOBN160002 REPLACE C232 SERIES	1,629,492
32	MAINSTEM FLOW AND TEMPERATURE	1,389,679
33	220MHZ SPECTRUM PURCHASE	1,367,707
34	BUILD ELDR SUBSTATION	1,340,164
35	BYRL170001 STA WORK FDR 013 FO	1,250,079
36	DONN-REPLACE METAL-CLAD E W/OP	1,234,321
37	HC SEDIMENT PROGRAMS	1,188,048
38	VARI170005 - GRID MOD PLAN, SC	1,175,785
39	SHOSHONE FALLS SITE ACCESS IMP	1,099,814
40	VARI160010 - MOBILE VEHICLE RA	1,085,492
41	HCC HOUSING RENOVATIONS #562,	1,041,293
42	SFP INTAKE MODIFICATION	1,040,071
43	TOTAL	480,258,675

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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	04/16/2019	End of 2018/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	BOCB170034 - MBE 9 PURCHASE A	1,028,571
2	Other Minor Projects Under $1,000,000	55,090,353
3		
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43	TOTAL	480,258,675

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

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

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

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	2,256,354,154	2,256,354,154		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	156,332,587	156,332,587		
4	(403.1) Depreciation Expense for Asset Retirement Costs	566,665	566,665		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	4,638,583	4,638,583		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):				
9	Fuel Stock	244,670	244,670		
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	161,782,505	161,782,505		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	61,786,072	61,786,072		
13	Cost of Removal	16,529,633	16,529,633		
14	Salvage (Credit)	2,965,438	2,965,438		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	75,350,267	75,350,267		
16	Other Debit or Cr. Items (Describe, details in footnote):	26,514,956	26,514,956		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	2,369,301,348	2,369,301,348		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	682,108,587	682,108,587		
21	Nuclear Production				
22	Hydraulic Production-Conventional	434,817,800	434,817,800		
23	Hydraulic Production-Pumped Storage				
24	Other Production	113,048,970	113,048,970		
25	Transmission	376,318,187	376,318,187		
26	Distribution	641,913,009	641,913,009		
27	Regional Transmission and Market Operation				
28	General	121,094,795	121,094,795		
29	TOTAL (Enter Total of lines 20 thru 28)	2,369,301,348	2,369,301,348		

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
Idaho Power Company	(1) X An Original (2) _ A Resubmission	(Mo, Da, Yr) 04/16/2019	2018/Q4

FOOTNOTE DATA

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

Includes: Valmy depreciation adjustments (ID 33771 and OR 17-235), CIAC 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	04/16/2019	End of 2018/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			69,749,884
5				
6	Subtotal Idaho Energy Resources Company			72,212,978
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42	Total Cost of Account 123.1 $ 2,463,094		TOTAL	72,212,978

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

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
8,813,793	24,000,000	54,563,677		4
				5
8,813,793	24,000,000	57,026,771		6
				7
				8
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8,813,793	24,000,000	57,026,771		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)	56,638,459	47,979,122	Electric
2	Fuel Stock Expenses Undistributed (Account 152)	5		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)	17,946,659	17,733,796	
8	Transmission Plant (Estimated)	10,011,948	9,422,601	
9	Distribution Plant (Estimated)	24,559,578	27,160,500	
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	1,338,445	-763,223	
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	53,856,630	53,553,674	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)	1,888,307	1,433,652	
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	112,383,401	102,966,448	

Schedule Page: 227 Line No.: 11 Column: c

This amount represents miscellaneous inventory that is not yet assigned to a particular function, offset by a year-end reserve for obsolete inventory.

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/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					
3					
4					
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12					
13					
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20					
21	**Generation Studies**				
22	BAKER CITY 1 SOLAR	269	186623	35,281	186623
23	JACKPOT ANNEX SOLAR #523	762	186623	(762)	186623
24	CAT CREEK PUMP STORAGE #524		186623	(7,861)	186623
25	ONTARIO SOLAR #525	8,918	186623	(362)	186623
26	WARM SPRINGS HYDRO #526		186623	(30,000)	186623
27	SHOSHONE FALLS HYDRO PROJECT IPCO		186623	(4,988)	186623
28	AMALGAMATED SUGAR #531	13,276	186623	(31,000)	186623
29	CAT CREEK PUMP STORAGE #530	8,566	186623	(60,000)	186623
30	GEM-VALE #534 300MW	9,780	186623	(70,000)	186623
31	GEM-VALE WIND #535 500MW	5,548	186623	(70,000)	186623
32	VERDE LIGHT POWER #532 3MW	2,465	186623	(11,000)	186623
33	BORREGO SOLAR #533	6,067	186623	(9,750)	186623
34	OLD CAMP SOLAR 80MW	1,721	186623	(60,000)	186623
35	MASON DAM HYDRO #538 2MW		186623	(500)	186623
36					
37					
38					
39					
40					

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

Amounts represent both reimbursements received (credit amounts)and refunds back to the counterparties (debit amounts). Refunds are initiated when the initial deposit exceeds the final expenses.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	Fixed Cost Adjustment (FCA) (182302)	15,542,127	34,502,069	400	15,542,127	34,502,069
2	Order Pending (Amort period 06/19 thru 05/20					
3						
4	AOCI Impact of Unfunded Post Retirement Liability	3,045,521		2283	3,153,456	-107,935
5	Order #30256 (182306)					
6						
7	FCA Calender Mo Adjustment	(704,075)	1,585,585			881,510
8	Order #33295 (182308)					
9						
10	Prior Year FCA - Order #33527 (182309)	16,017,844	15,606,711	400	24,504,916	7,119,639
11	(Amort period 06/18 thru 05/19) Order #34079					
12						
13	PCA Unbilled Amortization (182316)	(1,346,828)	1,346,828			
14						
15	AOCI Impact of Unfunded Pension Liability	277,120,492	15,225,643	2283	13,564,466	278,781,669
16	Order #30256 (182320)					
17						
18	Deferred Pension Expense Net of Contributions	23,032,921	36,152,743	1823	38,160,690	21,024,974
19	Order #30333 (182321)					
20						
21	FAS 109 Unfunded (182322)	322,260,285	35,942,056			358,202,341
22	Accum Deferred Income Noncurrent					
23						
24	PCA Prior Year Deferral (182324)	4,482,791		Various	4,482,791	
25	(Amort period 06/17 thru 05/18)					
26						
27	Idaho Pension Cash - Order #32248 (182327)	104,688,433	39,276,027	Various	17,153,713	126,810,747
28	(Amort period beginning 06/11 thru indefinite)					
29						
30	ASC 815 Mark to Market (182330)	1,419,163		244	508,638	910,525
31	Order #28661					
32						
33	Oregon Pension Expense Capitalized (182339)	4,397,606	634,828	4073	135,861	4,896,573
34	Order #10-064					
35						
36	Asset Retirement Obligations (182341)	15,629,470	1,934,008			17,563,478
37	IPUC Order #29414-OPUC Order #04-585					
38						
39	2008 PCAM Unbilled Amort (182356)	843		402	843	
40						
41	RA-Hells Canyon-Baker Co-Order #33948 (182360)	3,085,321		4073	2,771,815	313,506
42						
43	Lidar Surveys - Order #32426 (182361)	174,418		402	43,604	130,814

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	(Amort period 01/12 thru 12/21)					
2						
3	RA-Intervenor Funding-Idaho (182387)	150,754	41,717			192,471
4						
5	RA-CONTRA-DEF INC TAX (182389)	262,069,157		Various	6,127,411	255,941,746
6						
7	Idaho Boardman ARO - Order # 29414 (182393	130,669		Various	130,669	
8						
9	Langley Revenue Accrual - Order #12-226 (182398)	1,186,995	95,104			1,282,099
10						
11	RA-OR Langley Rev Int Res (182399)	(125,700)		4190	34,011	-159,711
12						
13	Siemens Long Term Deferred Rate Base (182410)	10,769,931		4073	431,488	10,338,443
14	Order #33420 (Amort period 01/16 thru 12/43)					
15						
16	Siemens Long Term Deferred Rate Base (182411)	16,070,904		4073	643,867	15,427,037
17	Order #33420 (Amort period 01/16 thru 12/43)					
18						
19	Siemens Long Term Deferred Rate Base (182412)	426,648	32,697	Various	44,047	415,298
20	Order #15-387 (Amort period 01/16 thru 12/36)					
21						
22	Siemens Long Term Deferred Rate Base (182413)	707,684		4073	39,316	668,368
23	Order #15-387 (Amort period 01/16 thru 12/36)					
24						
25	Seimens Long Term Interest Reserve (182414)	(67,865)		4190	32,697	-100,562
26						
27	RA-Valmy O&M ID 33771 (182432)	(738,442)		Various	1,969,609	-2,708,051
28						
29	RA-Valmy OR Depr Adj 17-325 (182434)	1,281,969		403	393,456	888,513
30	(Amort period 06/17 thru 12/25)					
31						
32	RA-Valmy Acctg Adj ID 33771 (182435)	44,107,596	33,142,248			77,249,844
33						
34	RA-Valmy Decomm OR (182436)	15,451	1,981,949			1,997,400
35	OPUC Order #17-235 (Amort period 06/17 thru 12/25					
36						
37	Idaho Boardman Decomissioning (182493)			Various	5,438,694	-5,438,694
38	Order #32549 & #32457					
39						
40	RA-ID Boardman Decomm (182495)		5,292,856			5,292,856
41	IPUC Order #32457					
42						
43	RA-OR Boardman Decomm (182496)		237,789			237,789

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	OPUC Order #12-235					
2						
3	Oregon DSM Rider (254202)	6,272,529	2,257,714	Various	7,132,494	1,397,749
4	Advice #05-03					
5						
6	Minor Items (10)	991,582	512,593	Various	1,282,263	221,912
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44	**TOTAL :**	1,132,096,194	225,801,165		143,722,942	1,214,174,417

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	1,008,962		431	262,302	746,660
2	Amortization period 11/16-11/20					
3						
4	Prepaid Services 186052	3,187,511	3,449,778	Various	2,963,449	3,673,840
5	Long-term portion					
6						
7	Workers Compensation 186121	1,020,064	98,548			1,118,612
8						
9	Prepaid ROW 186160	669,377	311,973	401	362,571	618,779
10	Long-term portion					
11						
12	CARB Inventory 186650		843,050			843,050
13						
14	Coal Royalties 186709	1,007,388		151	63,770	943,618
15						
16	Stable Value Life Inv 186719	43,159,437	2,310,575	4262	34,268	45,435,744
17						
18	Security Plan 186720	12,274,448	222,237	4262	1,929,146	10,567,539
19	Net Insurance Asset					
20						
21	Retiree Medical-COLI 186726	3,889,057	411,224	4262	451,188	3,849,093
22						
23	American Falls Water Rts 186727	7,380,895		401	1,042,008	6,338,887
24	Amortization period 01/06-02/25					
25						
26	American Falls Bond Refi 186770	343,994		401	47,999	295,995
27	Amortization period 12/09-02/25					
28						
29	Regulatory Reserves 186800	-2,772,230	1,649,843			-1,122,387
30						
31	Minor Items (6)	1,963,785	2,608,726	Various	4,476,898	95,613
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45						
46						
47	Misc. Work in Progress					
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	73,132,688				73,405,043

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)	89,557,247	96,930,307
6			
7	Other (See footnote)	182,469,703	178,068,785
8	TOTAL Electric (Enter Total of lines 2 thru 7)	272,026,950	274,999,092
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)	17,786,969	18,384,170
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	289,813,919	293,383,262

Notes

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

	Beginning Balance	Ending Balance
Construction Advances	1,420,074	1,082,811
Postretirement Benefits	436,208	313,224
USBR-American Falls O&M Costs Settlement	74,148	64,475
Non-VEBA Pension and Benefits	(238,565)	(468,289)
Executive Deferred Compensation	28,808	4,427
Retention Pay Accrual	21,449	0
Stock Based Compensation	3,209,060	3,437,429
Pension Expense-Oregon	2,714,789	3,019,304
Bridger Revenue Deferral	377,040	499,057
Asset Retirement Obligation (ARO)	1,230,333	1,423,588
Incentive Deferral-Profit Sharing-Not in Rates	3,752,926	3,491,132
OR Reconnect Fees Adv	237	955
Rate Case Disallowance	1,356,867	1,268,220
Prov for Rate Refund-HC Relicensing (AFUDC)	31,085,864	35,136,616
Revenue Sharing	0	1,293,322
VEBA-Post Retirement Benefits	7,854,162	8,976,089
Deferred Idaho ITC	29,195,228	26,408,291
Deferred GBC Federal	7,038,619	10,979,656
Total Other Electric	89,557,247	96,930,307

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

	Beginning Balance	Ending Balance
Pension-FAS 158	72,068,421	72,101,874
Regulatory Liability-FAS 109	98,743,759	98,042,217
Minimum Pension Liability	10,866,388	7,952,476
Postretirement Plan-FAS 158	791,135	(27,782)
Total Other	182,469,703	178,068,785

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

	Beginning Balance	Ending Balance
Senior Management Security Plan	17,786,969	18,384,170
Total Non Electric	17,786,969	18,384,170

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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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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	04/16/2019	End of 2018/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	04/16/2019	End of 2018/Q4

CAPITAL STOCK EXPENSE (Account 214)

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

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

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/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	1,199,383
4			235,300 D
5			
6	5.50% Series due 2033	70,000,000	728,701
7			36,400 D
8			
9	3.40% Series due 2020	100,000,000	1,159,871
10			499,000 D
11			
12	5.30% Series Due 2035	60,000,000	3,849,739
13			408,600 D
14			
15	4.00% Series due 2043	75,000,000	742,017
16			194,250 D
17			
18	6.00% Series due 2032	100,000,000	1,191,216
19			544,000 D
20			
21	5.875% Series due 2034	55,000,000	585,759
22			748,000 D
23			
24	5.50% Series due 2034	50,000,000	524,419
25			383,500 D
26			
27	4.85% Series Due 2040	100,000,000	1,284,871
28			170,000 D
29			
30	6.30% Series due 2037	140,000,000	1,500,031
31			278,600 D
32			
33	TOTAL	1,985,345,000	34,005,796

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	3/01/20	11/20/09	3/01/20		1,722,500	3
						4
						5
5/13/03	4/01/33	5/13/03	3/31/33	70,000,000	3,850,000	6
						7
						8
8/30/10	11/01/20	8/30/10	11/01/20	100,000,000	3,400,000	9
						10
						11
8/26/05	8/15/35	8/26/05	8/15/35	60,000,000	3,180,000	12
						13
						14
4/08/13	4/01/43	4/08/13	4/01/43	75,000,000	3,000,000	15
						16
						17
11/15/02	11/15/32	11/15/02	11/15/32	100,000,000	6,000,000	18
						19
						20
8/16/04	8/15/34	8/16/04	8/15/34	55,000,000	3,231,250	21
						22
						23
3/26/04	3/15/34	3/26/04	3/15/34	50,000,000	2,750,000	24
						25
						26
8/30/10	8/15/40	8/30/10	8/15/40	100,000,000	4,850,000	27
						28
						29
6/22/07	6/15/37	6/22/07	6/15/37	140,000,000	8,820,000	30
						31
						32
				1,855,345,000	84,407,634	33

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	6.25% Series due 2037	100,000,000	1,227,490
2			268,000 D
3			
4	Port of Morrow Variable due 2027	4,360,000	189,597
5			
6	Humboldt 5.15% due 2024	49,800,000	1,309,010
7			
8	Sweetwater 5.25% due 2026	116,300,000	3,044,152
9			
10	2.50% Series due 2023	75,000,000	648,267
11			374,250 D
12			
13	4.30% Series Due 2042	75,000,000	802,240
14			49,500 D
15			
16	2.95% Series Due 2022	75,000,000	708,490
17			128,250 D
18			
19	3.65% Series Due 2045	250,000,000	2,559,510
20			1,715,000 D
21			
22	4.05% Series Due 2046	120,000,000	1,311,383
23			309,600 D
24			
25	4.20% Series Due 2048	220,000,000	2,283,400
26	Idaho Order #33513 (4/27/16)		814,000 D
27	Oregon Order #16-151 (4/21/16)		
28	Wyoming Docket #20005-37-ES16 (5/17/16)		
29			
30	Subtotal Account 221	1,965,460,000	34,005,796
31			
32	Account 222 - Reaquired Bonds		
33	TOTAL	1,985,345,000	34,005,796

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.
10/18/07	10/15/37	10/18/07	10/15/37	100,000,000	6,250,000	1
						2
						3
5/17/00	2/01/27	05/17/00	02/01/27	4,360,000	70,934	4
						5
8/20/09	12/01/24	8/20/09	12/01/24	49,800,000	2,564,700	6
						7
8/20/09	7/15/26	8/20/09	7/15/26	116,300,000	6,105,750	8
						9
4/08/13	4/01/23	4/08/13	4/01/23	75,000,000	1,875,000	10
						11
						12
4/13/12	4/01/42	4/13/12	4/01/42	75,000,000	3,225,000	13
						14
						15
4/13/12	4/01/22	4/13/12	4/01/22	75,000,000	2,212,500	16
						17
						18
3/06/15	3/01/45	3/06/15	3/01/45	250,000,000	9,125,000	19
						20
						21
3/10/16	3/01/46	3/10/16	3/1/46	120,000,000	4,860,000	22
						23
						24
3/16/18	3/01/48	3/16/18	3/01/48	220,000,000	7,315,000	25
						26
						27
						28
						29
				1,835,460,000	84,407,634	30
						31
						32
				1,855,345,000	84,407,634	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	04/16/2019	End of 2018/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			
2	Account 223: Advances for Associated Companies		
3			
4	Account 224:		
5	Bond Guarantee - American Falls	19,885,000	
6	Subtotal Account 224	19,885,000	
7			
8			
9			
10			
11			
12			
13			
14			
15			
16			
17			
18			
19			
20			
21			
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32			
33	TOTAL	1,985,345,000	34,005,796

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD		Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
		Date From (f)	Date To (g)			
						1
						2
						3
						4
4/26/00	2/01/25			19,885,000		5
				19,885,000		6
						7
						8
						9
						10
						11
						12
						13
						14
						15
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						29
						30
						31
						32
				1,855,345,000	84,407,634	33

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Schedule Page: 256.1 Line No.: 25 Column: a

Unamortized debt expense at refunding is amortized by equal monthly amounts over the life of the new issue.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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)	222,334,291
2		
3		
4	Taxable Income Not Reported on Books	
5		8,247,297
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		202,142,160
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		78,820,082
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		149,211,232
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	204,692,434
28	Show Computation of Tax:	
29	Tentative Federal Tax @ 21%	42,985,411
30		
31		
32		
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34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

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

4005-AVOIDED COST	4,420,007
4003-CONSTRUCTION ADVANCES	(1,606,014)
4013-CIAC - TAXABLE - ACCT 107	2,060,896
4021-ENGINEERING FEES - TAXABLE - ACCT 107	143,041
4024-RENEWABLE ENERGY CERTIFICATES (REC) SALES	3,229,367
Total	**8,247,297**

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

Total Federal and State taxes deducted on books	**16,134,602**
5001-BAD DEBT EXPENSE	(203,121)
5002-INVENTORY RESERVE ADJUSTMENT	1,654,824
5024-NON-DEDUCTIBLE MEALS	492,000
5070-INCENTIVE DEFERRAL-CRI & RELIABILITY-INCLUDED IN RATES	5,366,162
5010-POSTEMPLOYMENT BENEFITS	0
5023-PENSION EXPENSE	17,153,713
5035-PCA EXPENSE DEFERRAL	0
5047-EXECUTIVE DEFERRED COMP	0
5053-STOCK BASED COMPENSATION	3,768,690
5058-FIXED COST ADJUSTMENT	(11,647,322)
5060-OREGON - PCAM	(786,312)
5061-PENSION EXPENSE - OREGON	1,279,263
5067-ASSET RETIREMENT OBLIGATION (ARO)	794,406
5071-INCENTIVE DEFERRAL-PROFIT SHARING-NOT IN RATES	753,926
5075-EIM DEFERRAL	772,395
5504-NON-DEDUCTIBLE POLITICAL EXPENSES	938,816
5505-SMSP - NET	2,950,584
7010-PROV FOR RATE REFUND - HC RELICENSING (AFUDC)	16,839,014
7012-REVENUE SHARING	5,024,562
8001-VEBA - POST RETIREMENT BENEFITS	4,642,456
8020-CONSERVATION EXPENSES	4,900,563
8009-DEPR TIMING DIFF - OPERATING - FEDERAL	129,512,939
8703-IPCO-162(m) THRESHHOLD	1,800,000
Total	**202,142,160**

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

5066-BOARDMAN DECOMMISSION	1,088,745
5074-VALMY SETTLEMENT ADJUSTMENT	6,584,633
5077-VALMY DEPRECIATION ADJUSTMENT	25,191,601
5501-SMSP - INSURANCE COSTS	2,397,329
7501-REVERSE EQUITY EARNINGS OF SUBSIDIARIES	8,813,793
7502-ALLOWANCE FOR OFUDC	24,352,523
7503-ALLOWANCE FOR BFUDC	10,151,313
7509-SMSP - INSURANCE PROCEEDS	240,145

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FOOTNOTE DATA

Total	**78,820,082**

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

5022-263A CAPITALIZED OVERHEADS	32,000,000
5538-STOCK BASED COMP - STOCK	3,539,111
8702-STOCK BASED COMP - DIVIDENDS	667,188
8034-REMOVAL COSTS	16,529,633
8042-GAIN/LOSS ON REACQUIRED DEBT	2,622,923
8073-REPAIRS DEDUCTION	85,000,000
8077-PREPAID INSURANCE & OTHER EXPENSES	(497,645)
8059-SOFTWARE - LABOR COSTS DEDUCTED - ACCT 107	4,280,000
8072-RELICENSING - LABOR COSTS DEDUCTED - ACCT 107	2,462,000
STATE INCOME TAX DEDUCTED ON FEDERAL RETURN	2,608,022
Total	**149,211,232**

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/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	-22,211,260		21,785,861	7,194,234	
3	Social Security - (FOAB)	431,833		15,595,269	15,649,443	
4	Unemployment	37,428		94,472	92,509	
5	Subtotal Federal	-21,741,999		37,475,602	22,936,186	
6						
7	State of Idaho:					
8	Income	-4,332,804		-2,635,249	-4,256,598	
9	Unemployment	22,775		199,492	208,194	
10	Property	9,841,215		22,845,101	22,578,849	
11	Non-Operating	9,044		17,648	17,868	
12	kWh	105,033		2,157,522	2,175,683	
13	Regulatory Commission			2,724,231	2,724,231	
14	Business License - Sho Ban			150	150	
15	Subtotal Idaho	5,645,263		25,308,895	23,448,377	
16						
17	State of Oregon					
18	Income	-357,714		525,059	489,294	
19	Unemployment	2,194		48,092	47,244	
20	Property		1,695,878	3,477,311	3,562,183	-513
21	Non-Operating Property		1,002	2,032	2,058	
22	Regulatory Commission			255,980	255,980	
23	Franchise	197,157		837,813	835,286	
24	Subtotal Oregon	-158,363	1,696,880	5,146,287	5,192,045	-513
25						
26	State of Montana:					
27	Property	179,456		340,253	349,735	
28	Subtotal Montana	179,456		340,253	349,735	
29						
30	State of Nevada:					
31	Property		415,074	839,633	846,710	
32	Subtotal Nevada		415,074	839,633	846,710	
33						
34	State of Wyoming					
35	Property	754,229		1,424,436	1,466,446	
36	Corporate License			4,202	4,202	
37	Subtotal Wyoming	754,229		1,428,638	1,470,648	
38						
39						
40						
41	TOTAL	-15,156,342	2,111,954	54,673,004	54,255,075	15,219

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/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
-7,619,635		20,035,445			1,750,416	2
377,660		15,595,269				3
39,391		94,472				4
-7,202,584		35,725,186			1,750,416	5
						6
						7
-2,711,454		-2,816,167			180,918	8
14,073		199,492				9
10,107,466		22,844,092			1,009	10
8,824					17,648	11
86,873		2,157,522				12
		2,724,231				13
		150				14
7,505,782		25,109,320			199,575	15
						16
						17
-321,948		515,365			9,694	18
3,042		48,092				19
	1,780,237	3,354,144			123,167	20
					2,032	21
		255,980				22
199,684		837,813				23
-119,222	1,780,237	5,011,394			134,893	24
						25
						26
169,975		340,253				27
169,975		340,253				28
						29
						30
	422,251	839,633				31
	422,251	839,633				32
						33
						34
712,218		1,424,436				35
		4,202				36
712,218		1,428,638				37
						38
						39
						40
1,306,621	2,202,488	52,584,791			2,088,213	41

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/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	11,000		9,687	9,687	
3	Subtotal Washington	11,000		9,687	9,687	
4						
5	Other States Income	155,143		61,334	7,237	
6	Canada GST Tax	-1,071			-5,550	15,732
7	Payroll Tax Credit			-15,937,325		
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20						
21						
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26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	-15,156,342	2,111,954	54,673,004	54,255,075	15,219

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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
11,000		9,687				2
11,000		9,687				3
						4
209,241		58,005			3,329	5
20,211						6
		-15,937,325				7
						8
						9
						10
						11
						12
						13
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						39
						40
1,306,621	2,202,488	52,584,791			2,088,213	41

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

```
Account 409.2        $     627,072
Account 409.1        $   1,123,344
                     -------------
Total                $   1,750,416
```

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

```
Account 409.2        $     180,918
```

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

```
Account 107          $       1,009
```

Schedule Page: 262 Line No.: 11 Column: l

```
Account 408.2        $      17,648
```

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

```
Account 409.2        $       9,694
```

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

A refund for erroneous taxes paid in the prior year.

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

```
Account 107          $     123,167
```

Schedule Page: 262 Line No.: 21 Column: l

```
Account 408.2        $       2,032
```

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

```
Account 409.2        $       3,329
```

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

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

Schedule Page: 262.1 Line No.: 7 Column: i

This amount is an offset to lines 3, 4, 9, and 19. 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.

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year: Account No. (c)	Deferred for Year: Amount (d)	Allocations to Current Year's Income: Account No. (e)	Allocations to Current Year's Income: Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%	277,580			411.401	33,820	
4	7%						
5	10%	15,246,145			411.401	1,634,952	
6	Other- Federal	8,054,933		3,941,037		22,270	
7	Other- State	63,806,080	411.402	4,393,349	411.402	1,238,246	
8	TOTAL	87,384,738		8,334,386		2,929,288	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10	11%	1,086,186			411.401	22,270	
11	30%	6,968,747	411.401	3,941,037			
12	Total Line No. 6	8,054,933		3,941,037		22,270	
13							
14							
15	State of Idaho	63,806,080	411.402	4,393,349	411.402	1,238,246	
16							
17							
18							
19							
20							
21							
22							
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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
243,760	8.21		3
			4
13,611,193	9.33		5
11,973,700			6
66,961,183	51.53		7
92,789,836			8
			9
1,063,916	48.78		10
10,909,784			11
11,973,700			12
			13
			14
66,961,183			15
			16
			17
			18
			19
			20
			21
			22
			23
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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	04/16/2019	End of 2018/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	PTP Transmission Deposits 253201	1,847,225	237	526,788	275,000	1,595,437
2						
3	FTV Dark Fiber Rental 253202	1,666,666	400	400,000		1,266,666
4	Amortization period 03/98-02/23					
5						
6	Sho-Ban Scholarships 253480	157,500	242	15,000		142,500
7	Amortization period 01/05-12/27					
8						
9	Operations Accrual 253550	438,284	Various	59,326	117,992	496,950
10						
11	Postretirement Benefits 253960	1,216,876			238,856	1,455,732
12						
13	Directors Deferred Compensation	3,419,719	401	413,236	342,239	3,348,722
14	253970-253999					
15						
16						
17						
18						
19						
20						
21						
22						
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43						
44						
45						
46						
47	TOTAL	8,746,270		1,414,350	974,087	8,306,007

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	300,592,058	5,256,947	20,716,527
3	Gas			
4	Other			
5	TOTAL (Enter Total of lines 2 thru 4)	300,592,058	5,256,947	20,716,527
6	Non-Operating Property			
7	Other - Regulatory Asset	584,329,442		
8	Like Kind Exchange- Reclass No	5,409,423		
9	TOTAL Account 282 (Enter Total of lines 5 thru	890,330,923	5,256,947	20,716,527
10	Classification of TOTAL			
11	Federal Income Tax	716,118,788	5,197,164	20,612,598
12	State Income Tax	174,212,135	59,783	103,929
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) 04/16/2019	Year/Period of Report End of 2018/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
		254	3,359,749	282/254	7,510,559	289,283,288	2
							3
							4
			3,359,749		7,510,559	289,283,288	5
							6
				182	29,814,644	614,144,086	7
				282	-221,698	5,187,725	8
			3,359,749		37,103,505	908,615,099	9
							10
		254	3,359,749	182/254	36,165,721	733,509,326	11
				182	937,785	175,105,774	12
							13

NOTES (Continued)

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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	(Mo, Da, Yr) 04/16/2019	2018/Q4

FOOTNOTE DATA

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

Account (a)	2018 Beginning Balance b	Changes during Year DR to 410.1 c	Changes during Year CR to 411.1 d	Adjustments Debits Acct. credited g	Adjustments Debits Amount h	Adjustments Credits Acct. debited i	Adjustments Credits Amount j	2018 Ending Balance k
Depreciation Timing Diff-Operating	490,499,923	3,689,100	20,253,701		-		-	473,935,322
Like Kind Exchange - Reclass Non-Rate Base	(5,409,423)	-	-		-	282111	221,698	(5,187,725)
Excess Deferred Tax on Depreciation (Reg Liab)	(193,991,452)	-	-	254967	3,359,749	254967	7,288,861	(190,062,340)
CIAC-Taxable-Acct 107	(3,266,525)	103,284	432,788		-		-	(3,596,029)
Engineering Fees-Taxable-Acct 107	(416,628)	47	30,038		-		-	(446,619)
Software-Labor Costs Deducted-Acct 107	1,975,684	861,113	-		-		-	2,836,797
Intangible-Labor Costs Deducted-Acct 107	11,200,479	603,403	-		-		-	11,803,882
TOTAL	300,592,058	5,256,947	20,716,527		3,359,749		7,510,559	289,283,288

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	51,700,165	30,518,469	15,060,757
4				
5				
6				
7				
8	Other -- See Note	72,859,556		
9	TOTAL Electric (Total of lines 3 thru 8)	124,559,721	30,518,469	15,060,757
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other -- See Note	-3,260	184	11,350
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	124,556,461	30,518,653	15,072,107
20	Classification of TOTAL			
21	Federal Income Tax	94,348,750	23,148,824	10,815,784
22	State Income Tax	30,207,711	7,369,829	4,256,324
23	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) 04/16/2019	Year/Period of Report End of 2018/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
						67,157,877	3
							4
							5
							6
							7
				190	-785,464	72,074,092	8
					-785,464	139,231,969	9
							10
							11
							12
							13
							14
							15
							16
							17
						-14,426	18
					-785,464	139,217,543	19
							20
				190	84,111	106,765,901	21
				190	-869,575	32,451,641	22
							23

NOTES (Continued)

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

Account (a)	2018 Beginning Balance b	Changes during Year DR to 410.1 c	 CR to 411.1 d	2018 Ending Balance k
Renewable Energy Certificates (REC) Sales	126,691	515,640	837,100	(194,769)
Royalty Income	237,340	17	3,959	233,398
Pension Expense	30,547,823	10,609,226	4,790,860	36,366,190
PCA Expense	-	-	-	-
Intervenor Funding Orders	76,300	156	17,748	58,708
Fixed Cost Adjustment	8,015,436	2,998,021	73,129	10,940,327
PS & I Costs	103,957	632	70,253	34,336
Oregon PCAM	(202,380)	204,243	-	1,863
2011 LIDAR Surveys Deferral	56,636	103	11,844	44,895
Boardman Decommission	377,412	286,282	665,342	(1,648)
Valmy Settlement Adjustment	11,159,753	1,757,818	6,999,800	5,917,771
EIM Deferral	209,469	260	200,728	9,001
Valmy Depreciation Adjustment	-	13,361,104	62,740	13,298,364
Langley Revenue Accrual	(444,450)	415,851	3,756	(32,355)
Conservation Expenses	1,248,806	353,436	1,276,023	326,219
Siemens LTP Contract	46,153	13,237	541	58,849
Prepaid Credit Facility	144,428	337	38,193	106,572
Siemens OR DRB Interest Reserve	(8,958)	161	8,671	(17,468)
Boardman Removal Costs	5,749	1,945	70	7,624
TOTAL	51,700,165	30,518,469	15,060,757	67,157,877

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

Account (a)	2018 Beginning Balance b	Changes during Year DR to 410.1 c	 CR to 411.1 d	Adjustments Credits Acct. debited i	 Amount j	2018 Ending Balance k
Pension-FAS 158	72,068,421	-	-	190	33,454	72,101,875
Postretirement Plan-FAS 158	791,135	-	-	190	(818,918)	(27,783)
TOTAL	72,859,556	-	-	190	(785,464)	72,074,092

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

Account (a)	2018 Beginning Balance b	Changes during Year DR to 410.1 c	 CR to 411.1 d	2018 Ending Balance k
EDC-Unrealized Gain/Loss From Rabbit Trust	4,473	41	4,577	(63)
SMSP-Unrealized Gain/Loss From Rabbi Trust	(7,986)	135	6,771	(14,622)
Oregon Non-Op Prop Tax Adj	253	8	2	259
TOTAL	(3,260)	184	11,350	(14,426)

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)	18,155			3,682,258	3,700,413
2	IPUC Order #28661					
3						
4	Idaho DSM Rider (254201)	407,604	Various	33,663,001	38,514,354	5,258,957
5	IPUC Order #29026					
6						
7	BPA Credit Residential Idaho (254401)	964,483	Various	10,002,245	10,935,151	1,897,389
8	Advice #15-13					
9						
10	BPA Credit Residential Oregon (254402)	93,231	Various	389,190	391,643	95,684
11	Advice #15-11					
12						
13	BPA Credit Farm Idaho (254403)	(34,946)	Various	1,597,875	1,971,280	338,459
14	Advice #15-13					
15						
16	BPA Credit Farm Oregon (254404)	1,734	Various	95,603	108,359	14,490
17	Advice #15-11					
18						
19	Oregon Green Tags (254415)	108,044	Various	64,651	128,439	171,832
20	Advice #11-086					
21						
22	Idaho Tax Settlement (254451)				1,721,624	1,721,624
23	IPUC Order #34071					
24						
25	Oregon Tax Settlement (254452)				564,308	564,308
26	OPUC Advice #18-199					
27						
28	Bridger Depreciation (254800)	1,938,839			597,686	2,536,525
29	OPUC Order #12-296					
30						
31	RL-WAQC CRYOVR (254901)	104,602			25,782	130,384
32	IPUC Order #29505					
33						
34	Unfunded Accum Def Income Tax (254966)	30,666,054			1,496,757	32,162,811
35						
36	RL-DEF INC TAX-ARAM (254967)	193,991,452	Various	3,929,111		190,062,341
37						
38	RL-DEF INC TAX-ARAM GROSS-UP (254968)	68,077,705	Various	2,198,300		65,879,405
39						
40	Idaho Revenue Sharing (254101)				5,024,562	5,024,562
41	TOTAL	307,404,206		81,642,922	126,021,696	351,782,980

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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	04/16/2019	End of 2018/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 (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	IPUC Order Pending					
2						
3	RA-PCA Deferral-ID (254425)	5,336,641	Various	23,059,065	59,876,231	42,153,807
4						
5	RA-OR BDMN Decomm Order #12-235	147,904	Various	147,904		
6						
7	Minor Items (6)	5,582,704		6,495,977	983,262	69,989
8						
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35						
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37						
38						
39						
40						
41	TOTAL	307,404,206		81,642,922	126,021,696	351,782,980

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457 2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	533,062,028	552,333,276
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	466,201,600	465,145,591
5	Large (or Ind.) (See Instr. 4)	191,175,361	195,124,244
6	(444) Public Street and Highway Lighting	4,032,545	4,079,095
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	1,194,471,534	1,216,682,206
11	(447) Sales for Resale	79,156,537	33,381,940
12	TOTAL Sales of Electricity	1,273,628,071	1,250,064,146
13	(Less) (449.1) Provision for Rate Refunds	19,972,541	10,706,040
14	TOTAL Revenues Net of Prov. for Refunds	1,253,655,530	1,239,358,106
15	Other Operating Revenues		
16	(450) Forfeited Discounts		
17	(451) Miscellaneous Service Revenues	4,463,096	4,273,744
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	16,048,736	15,236,098
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	36,461,056	39,921,003
22	(456.1) Revenues from Transmission of Electricity of Others	51,329,032	42,071,453
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	108,301,920	101,502,298
27	TOTAL Electric Operating Revenues	1,361,957,450	1,340,860,404

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/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
5,134,576	5,354,568	459,128	448,800	2
				3
6,049,156	5,838,862	88,929	87,675	4
3,370,566	3,345,712	118	120	5
32,224	31,812	3,280	2,995	6
				7
				8
				9
14,586,522	14,570,954	551,455	539,590	10
2,863,637	2,135,649			11
17,450,159	16,706,603	551,455	539,590	12
				13
17,450,159	16,706,603	551,455	539,590	14

Line 12, column (b) includes $ -6,071,163 of unbilled revenues.

Line 12, column (d) includes -15,220 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)	$4,191,763
Misc. Under $250,000	271,333
Total Account 451	$4,463,096

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

This amount consists of:

Alternate Distribution Service	$ 592,364
DSM Activity	35,702,948
Misc. Under $250,000	165,744
Total Account 456	$36,461,056

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	440 - Residential Sales:					
2	01 - Residential	5,115,376	518,023,382	455,721	11,225	0.1013
3	03 - Residential Master Meter	4,609	447,826	23	200,391	0.0972
4	05 - Residential - TOD	19,171	1,880,049	1,159	16,541	0.0981
5	06 - Residential On-Site Generati	14,316	1,530,181	2,225	6,434	0.1069
6	15 - Dusk to dawn lighting	2,634	645,239			0.2450
7	Unbilled Revenues	-21,530	-4,959,747			0.2304
8	Other Revenues		15,495,098			
9	Total 440	5,134,576	533,062,028	459,128	11,183	0.1038
10						
11	442-Commercial & Industrial Sales					
12	07 - General service	149,668	18,585,424	31,016	4,826	0.1242
13	08 - General service On-Site Gene	226	28,289	43	5,256	0.1252
14	09P - General service	542,007	35,660,806	244	2,221,340	0.0658
15	09S - General service	3,366,257	249,273,645	35,547	94,699	0.0741
16	09T - General service	6,534	456,427	4	1,633,500	0.0699
17	15 - Dusk to Dawn Light	4,312	755,243			0.1751
18	19P - Uniform rate contracts	2,298,361	133,757,391	111	20,705,955	0.0582
19	19S - Uniform rate contracts	6,012	388,232	1	6,012,000	0.0646
20	19T - Uniform rate contracts	142,742	8,195,430	3	47,580,667	0.0574
21	24S - Irrigation Pumping	1,976,587	156,436,905	21,104	93,659	0.0791
22	40 - General service	10,431	906,986	971	10,743	0.0870
23	Special Contracts	910,281	46,514,419	3	303,427,000	0.0511
24	Commercial & Industrial Unbill	6,304	-1,095,858			-0.1738
25	Other Revenues		7,513,622			
26	Total 442	9,419,722	657,376,961	89,047	105,784	0.0698
27						
28	444 - Public Street Lighting:					
29	40 - General service	786	68,697	468	1,679	0.0874
30	41 - Street lighting	28,636	3,775,167	2,181	13,130	0.1318
31	42 - Traffic control lighting	2,796	177,646	631	4,431	0.0635
32	Unbilled	6	-15,563			-2.5938
33	Other Revenues		26,598			
34	Total 444	32,224	4,032,545	3,280	9,824	0.1251
35						
36						
37						
38						
39						
40						
41	TOTAL Billed	14,601,742	1,200,542,697	551,455	26,479	0.0822
42	Total Unbilled Rev.(See Instr. 6)	-15,220	-6,071,163	0	0	0.3989
43	TOTAL	14,586,522	1,194,471,534	551,455	26,451	0.0819

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	WSPP			
2	Arizona Public Service Co.	SF	WSPP			
3	Avangrid Renewables (IBERDROLA)	OS	OATT			
4	AVANGRID RENEWABLES, LLC	SF	WSPP			
5	Avista Corp.	OS	WSPP			
6	Avista Corp.	SF	WSPP			
7	Avista Corp. - WWP Div.	OS	OATT			
8	Basin Electric Power Cooperative	OS	WSPP			
9	Basin Electric Power Cooperative	SF	WSPP			
10	Black Hills Power Inc.	OS	WSPP			
11	Black Hills Power Inc.	SF	WSPP			
12	Black Hills Power Inc.	OS	OATT			
13	Bonneville Power	OS	OATT			
14	Bonneville Power Administration	SF	WSPP			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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.
			1,328,994	1,328,994	1
11,703		300,358		300,358	2
			8,064	8,064	3
9,433		221,941		221,941	4
6,350			46,400	46,400	5
395,700		5,835,801		5,835,801	6
			420	420	7
9,986			25,544	25,544	8
5,155		9,670		9,670	9
500			2,500	2,500	10
31,261		252,121		252,121	11
			447	447	12
			2,207,278	2,207,278	13
115,004		3,680,760		3,680,760	14
0	0	0	0	0	
2,863,637	0	69,701,180	9,455,357	79,156,537	
2,863,637	**0**	**69,701,180**	**9,455,357**	**79,156,537**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/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	BP Energy Company	SF	WSPP			
2	Brookfield Energy Marketing	OS	OATT			
3	Brookfield Energy Marketing LP	SF	WSPP			
4	California Independent System Operator	SF	CAISO			
5	Chelan Co PUD	SF	WSPP			
6	Citigroup Energy Inc.	SF	WSPP			
7	Citigroup Energy Inc.	OS	ISDA			
8	Clatskanie PUD	SF	WSPP			
9	CWP Energy	OS	OATT			
10	DTE Energy Trading, Inc.	SF	WSPP			
11	EDF Trading North America (EAGL)	OS	OATT			
12	EDF Trading North America, LLC	SF	WSPP			
13	Energy Keepers, Inc	SF	WSPP			
14	Energy Keepers, Inc.	OS	OATT			
	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) 04/16/2019	Year/Period of Report End of 2018/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.
21,971		677,972		677,972	1
			62,334	62,334	2
250		4,020		4,020	3
155,921		9,593,527		9,593,527	4
263		2,996		2,996	5
7,185		85,561		85,561	6
			-21,912	-21,912	7
559		10,313		10,313	8
			3,154	3,154	9
75,425		2,512,980		2,512,980	10
			4,164	4,164	11
103,587		2,334,744		2,334,744	12
44		754		754	13
			35,919	35,919	14
0	0	0	0	0	
2,863,637	0	69,701,180	9,455,357	79,156,537	
2,863,637	**0**	**69,701,180**	**9,455,357**	**79,156,537**	

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.

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Eugene Water & Electric Board	SF	WSPP			
2	Exelon Generation Company, LLC	SF	WSPP			
3	J.Aron & Company LLC	OS	ISDA			
4	Los Angeles Department of Water & Power	SF	WSPP			
5	Macquarie Energy LLC	SF	WSPP			
6	Macquarie Energy LLC	OS	OATT			
7	Macquarie Energy LLC	OS	ISDA			
8	MAG Energy Solutions	OS	OATT			
9	Morgan Stanley Capital Group Inc.	OS	ISDA			
10	Morgan Stanley Capital Group Inc.	SF	ISDA			
11	Morgan Stanley Capital Group Inc.	OS	OATT			
12	Municipal Energy Agency of Nebraska	SF	WSPP			
13	Nevada Power	OS	OATT			
14	Nevada Power Company, dba NV Energy	SF	WSPP			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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,line 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
5,261		110,525		110,525	1
222,475		6,414,888		6,414,888	2
			40,298	40,298	3
10,800		314,550		314,550	4
16,148		153,249		153,249	5
			5,669	5,669	6
			-30,892	-30,892	7
			61,826	61,826	8
13,615			71,105	71,105	9
186,371		2,062,064		2,062,064	10
			2,070,600	2,070,600	11
857		11,727		11,727	12
			5,391	5,391	13
19,871		1,156,888		1,156,888	14
0	0	0	0	0	
2,863,637	0	69,701,180	9,455,357	79,156,537	
2,863,637	**0**	**69,701,180**	**9,455,357**	**79,156,537**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	NorthWestern Energy	SF	WSPP			
2	NorthWestern Energy NWDS	OS	OATT			
3	PacifiCorp	OS	WSPP			
4	PacifiCorp	SF	WSPP			
5	PacifiCorp	OS	T-7			
6	PacifiCorp Inc.	OS	OATT			
7	PacifiCorp Inc. - Imnaha	OS	OATT			
8	Portland General Electric Company	SF	WSPP			
9	Portland General Electric Company	OS	OATT			
10	Powerex Corp.	OS	WSPP			
11	Powerex Corp.	SF	WSPP			
12	Powerex Corp.	OS	OATT			
13	Public Service Company of Colorado	SF	WSPP			
14	Puget Sound Energy, Inc.	SF	WSPP			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
9,072		125,205		125,205	1
			96	96	2
8,199			47,449	47,449	3
236,151		5,510,649		5,510,649	4
51			1,754	1,754	5
			2,615,958	2,615,958	6
			49	49	7
127,686		5,224,361		5,224,361	8
			86,089	86,089	9
3,950			8,400	8,400	10
16,751		170,957		170,957	11
			47,019	47,019	12
26		685		685	13
24,436		451,822		451,822	14
0	0	0	0	0	
2,863,637	0	69,701,180	9,455,357	79,156,537	
2,863,637	**0**	**69,701,180**	**9,455,357**	**79,156,537**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/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	Rainbow Energy Marketing Corporation	SF	WSPP			
2	Rainbow Energy Marketing Corporation	OS	OATT			
3	Salt River Project	SF	WSPP			
4	Seattle City Light	OS	WSPP			
5	Seattle City Light	SF	WSPP			
6	Seattle City Light	OS	WSPP			
7	Shell Energy North America (US), L.P.	OS	WSPP			
8	Shell Energy North America (US), L.P.	SF	WSPP			
9	Shell Energy North America (US), L.P.	OS	OATT			
10	Sierra Pacific Power Co., dba NV Energy	OS	T-7			
11	Snohomish County PUD	SF	WSPP			
12	Tacoma Power	SF	WSPP			
13	Tenaska Power Services Co.	SF	WSPP			
14	Tenaska Power Services Co.	OS	OATT			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
25,664		85,112		85,112	1
			45,425	45,425	2
2		92		92	3
1,350			9,150	9,150	4
181,998		2,708,676		2,708,676	5
5			65	65	6
20,677			141,479	141,479	7
576,823		14,356,955		14,356,955	8
			426,243	426,243	9
68			2,100	2,100	10
928		28,515		28,515	11
5,877		126,598		126,598	12
2,083		151,825		151,825	13
			3,497	3,497	14
0	0	0	0	0	
2,863,637	0	69,701,180	9,455,357	79,156,537	
2,863,637	**0**	**69,701,180**	**9,455,357**	**79,156,537**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	The Energy Authority, Inc.	SF	WSPP			
2	The Energy Authority, Inc.	OS	OATT			
3	TransAlta Energy Marketing (U.S.) Inc.	SF	WSPP			
4	TransAlta Energy Marketing (U.S.) Inc.	OS	OATT			
5	Utah Associated Municipal Power Systems	SF	WSPP			
6	Utah Associated Municipal Power Systems	OS	OATT			
7	Westar Energy, Inc.	SF	WSPP			
8	Transmission Penalty Distribution	OS	-			
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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.
121,031		2,859,594		2,859,594	1
			3,658	3,658	2
70,099		2,063,037		2,063,037	3
			68,811	68,811	4
5,000		89,688		89,688	5
			2,803	2,803	6
15					7
			18,009	18,009	8
					9
					10
					11
					12
					13
					14
0	0	0	0	0	
2,863,637	0	69,701,180	9,455,357	79,156,537	
2,863,637	**0**	**69,701,180**	**9,455,357**	**79,156,537**	

Schedule Page: 310 Line No.: 1 Column: b
ADM Investor Services, Inc Futures Account Document, dated May 5, 2015
Schedule Page: 310 Line No.: 3 Column: b
Financial Transmission Losses
Schedule Page: 310 Line No.: 5 Column: b
Non-firm Sales
Schedule Page: 310 Line No.: 7 Column: b
Financial Transmission Losses
Schedule Page: 310 Line No.: 8 Column: b
Non-firm Sales
Schedule Page: 310 Line No.: 10 Column: b
Non-firm Sales
Schedule Page: 310 Line No.: 12 Column: b
Financial Transmission Losses
Schedule Page: 310 Line No.: 13 Column: b
Financial Transmission Losses
Schedule Page: 310.1 Line No.: 2 Column: b
Financial Transmission Losses
Schedule Page: 310.1 Line No.: 7 Column: b
ISDA Master Agreement with Citigroup Energy Inc. dated March 7, 2011
Schedule Page: 310.1 Line No.: 9 Column: b
Financial Transmission Losses
Schedule Page: 310.1 Line No.: 11 Column: b
Financial Transmission Losses
Schedule Page: 310.1 Line No.: 14 Column: b
Financial Transmission Losses
Schedule Page: 310.2 Line No.: 3 Column: b
ISDA Master Agreement with J. Aron & Company dated April 30, 2014
Schedule Page: 310.2 Line No.: 6 Column: b
Financial Transmission Losses
Schedule Page: 310.2 Line No.: 7 Column: b
ISDA Master Agreement with Macquarie Energy, LLC dated April 12, 2011
Schedule Page: 310.2 Line No.: 8 Column: b
Financial Transmission Losses
Schedule Page: 310.2 Line No.: 9 Column: b
Non-firm Sales
Schedule Page: 310.2 Line No.: 11 Column: b
Financial Transmission Losses
Schedule Page: 310.2 Line No.: 13 Column: b
Financial Transmission Losses
Schedule Page: 310.3 Line No.: 2 Column: b
Financial Transmission Losses
Schedule Page: 310.3 Line No.: 3 Column: b
Non-firm Sales
Schedule Page: 310.3 Line No.: 5 Column: b
Spinning or Operating Reserves
Schedule Page: 310.3 Line No.: 6 Column: b
Financial Transmission Losses
Schedule Page: 310.3 Line No.: 7 Column: b
Financial Transmission Losses
Schedule Page: 310.3 Line No.: 9 Column: b
Financial Transmission Losses
Schedule Page: 310.3 Line No.: 10 Column: b
Non-firm Sales

Name of Respondent Idaho Power Company	This Report is: (1) X An Original (2) _ A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report 2018/Q4

FOOTNOTE DATA

Schedule Page: 310.3 Line No.: 12 Column: b
Financial Transmission Losses

Schedule Page: 310.4 Line No.: 2 Column: b
Financial Transmission Losses

Schedule Page: 310.4 Line No.: 4 Column: b
Non-firm Sales

Schedule Page: 310.4 Line No.: 6 Column: b
Spinning or Operating Reserves

Schedule Page: 310.4 Line No.: 7 Column: b
Non-firm Sales

Schedule Page: 310.4 Line No.: 9 Column: b
Financial Transmission Losses

Schedule Page: 310.4 Line No.: 10 Column: b
Spinning or Operating Reserves

Schedule Page: 310.4 Line No.: 14 Column: b
Financial Transmission Losses

Schedule Page: 310.5 Line No.: 2 Column: b
Financial Transmission Losses

Schedule Page: 310.5 Line No.: 4 Column: b
Financial Transmission Losses

Schedule Page: 310.5 Line No.: 6 Column: b
Financial Transmission Losses

Schedule Page: 310.5 Line No.: 8 Column: b
Transmission penalty distribution credits

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	1,204,942	978,720
5	(501) Fuel	115,523,971	107,893,663
6	(502) Steam Expenses	9,912,734	8,501,434
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	1,868,433	1,396,032
10	(506) Miscellaneous Steam Power Expenses	9,134,293	11,694,905
11	(507) Rents	250,861	328,946
12	(509) Allowances		
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	137,895,234	130,793,700
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	213,256	55,228
16	(511) Maintenance of Structures	349,423	440,434
17	(512) Maintenance of Boiler Plant	10,847,201	11,031,366
18	(513) Maintenance of Electric Plant	4,545,026	4,331,373
19	(514) Maintenance of Miscellaneous Steam Plant	7,142,704	5,935,275
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	23,097,610	21,793,676
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	160,992,844	152,587,376
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	5,629,020	5,699,366
45	(536) Water for Power	9,123,648	5,857,068
46	(537) Hydraulic Expenses	15,387,250	15,008,403
47	(538) Electric Expenses	1,884,840	1,912,278
48	(539) Miscellaneous Hydraulic Power Generation Expenses	5,600,843	8,270,822
49	(540) Rents	246,704	241,787
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	37,872,305	36,989,724
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	93,530	94,013
54	(542) Maintenance of Structures	745,081	1,139,095
55	(543) Maintenance of Reservoirs, Dams, and Waterways	332,571	821,883
56	(544) Maintenance of Electric Plant	2,988,299	1,877,280
57	(545) Maintenance of Miscellaneous Hydraulic Plant	2,666,883	2,819,560
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	6,826,364	6,751,831
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	44,698,669	43,741,555

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	648,947	687,916
63	(547) Fuel	17,673,949	37,935,165
64	(548) Generation Expenses	4,513,426	4,171,670
65	(549) Miscellaneous Other Power Generation Expenses	1,406,549	986,828
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)	24,242,871	43,781,579
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	40	226
70	(552) Maintenance of Structures	215,293	335,091
71	(553) Maintenance of Generating and Electric Plant	124,643	595,085
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	2,641,004	2,226,109
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	2,980,980	3,156,511
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	27,223,851	46,938,090
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	287,762,141	244,381,204
77	(556) System Control and Load Dispatching	5,331	2,885
78	(557) Other Expenses	46,535,908	56,007,259
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	334,303,380	300,391,348
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	567,218,744	543,658,369
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	3,318,397	3,150,433
84			
85	(561.1) Load Dispatch-Reliability	10,084	11,169
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	2,117,726	1,620,215
87	(561.3) Load Dispatch-Transmission Service and Scheduling	1,440,842	1,526,249
88	(561.4) Scheduling, System Control and Dispatch Services	6,438	
89	(561.5) Reliability, Planning and Standards Development		
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies	35,961	32,101
92	(561.8) Reliability, Planning and Standards Development Services	1,715,639	1,698,457
93	(562) Station Expenses	2,855,188	2,887,872
94	(563) Overhead Lines Expenses	878,708	1,070,029
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	3,602,155	4,568,399
97	(566) Miscellaneous Transmission Expenses	15,165	25
98	(567) Rents	2,710,673	4,782,018
99	TOTAL Operation (Enter Total of lines 83 thru 98)	18,706,976	21,346,967
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	712,201	154,736
102	(569) Maintenance of Structures	-2,653	
103	(569.1) Maintenance of Computer Hardware	33,857	31,344
104	(569.2) Maintenance of Computer Software	1,024,304	925,878
105	(569.3) Maintenance of Communication Equipment	15,553	8,099
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	1,721,024	1,925,172
108	(571) Maintenance of Overhead Lines	832,096	883,265
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant		3,357
111	TOTAL Maintenance (Total of lines 101 thru 110)	4,336,382	3,931,851
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	23,043,358	25,278,818

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	411,723	
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	411,723	
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)	411,723	
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	4,550,906	4,208,616
135	(581) Load Dispatching	4,354,562	4,166,896
136	(582) Station Expenses	1,565,905	1,555,734
137	(583) Overhead Line Expenses	3,896,819	4,916,620
138	(584) Underground Line Expenses	3,392,139	3,615,140
139	(585) Street Lighting and Signal System Expenses	157,861	118,675
140	(586) Meter Expenses	4,570,706	4,904,919
141	(587) Customer Installations Expenses	1,287,251	1,276,382
142	(588) Miscellaneous Expenses	4,939,645	6,886,864
143	(589) Rents	1,203,806	381,320
144	TOTAL Operation (Enter Total of lines 134 thru 143)	29,919,600	32,031,166
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	604,934	-1,643,939
147	(591) Maintenance of Structures	-1,048	
148	(592) Maintenance of Station Equipment	4,482,318	3,887,158
149	(593) Maintenance of Overhead Lines	17,401,297	13,818,926
150	(594) Maintenance of Underground Lines	703,795	748,181
151	(595) Maintenance of Line Transformers	45,593	23,843
152	(596) Maintenance of Street Lighting and Signal Systems	589,313	554,421
153	(597) Maintenance of Meters	911,444	982,875
154	(598) Maintenance of Miscellaneous Distribution Plant	214,170	240,442
155	TOTAL Maintenance (Total of lines 146 thru 154)	24,951,816	18,611,907
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	54,871,416	50,643,073
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	1,116,501	945,821
160	(902) Meter Reading Expenses	1,790,512	1,544,764
161	(903) Customer Records and Collection Expenses	13,951,112	14,205,692
162	(904) Uncollectible Accounts	3,350,112	5,732,560
163	(905) Miscellaneous Customer Accounts Expenses	-4	-944
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	20,208,233	22,427,893

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	802,563	821,144
168	(908) Customer Assistance Expenses	42,486,187	44,176,525
169	(909) Informational and Instructional Expenses	341,699	444,538
170	(910) Miscellaneous Customer Service and Informational Expenses	627,857	641,841
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	44,258,306	46,084,048
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		
175	(912) Demonstrating and Selling Expenses		
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)		
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	88,828,776	79,079,418
182	(921) Office Supplies and Expenses	14,790,380	14,134,583
183	(Less) (922) Administrative Expenses Transferred-Credit	29,219,811	27,762,969
184	(923) Outside Services Employed	7,744,133	6,769,731
185	(924) Property Insurance	3,010,285	3,117,561
186	(925) Injuries and Damages	5,617,495	5,647,112
187	(926) Employee Pensions and Benefits	52,315,074	46,786,554
188	(927) Franchise Requirements		
189	(928) Regulatory Commission Expenses	5,021,358	4,260,709
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	603,786	364,410
192	(930.2) Miscellaneous General Expenses	3,605,153	3,556,441
193	(931) Rents		-350
194	TOTAL Operation (Enter Total of lines 181 thru 193)	152,316,629	135,953,200
195	Maintenance		
196	(935) Maintenance of General Plant	6,842,171	6,737,813
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	159,158,800	142,691,013
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	869,170,580	830,783,214

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	American Falls Solar, LLC	LU		N/A	N/A	N/A
2	American Falls Solar II, LLC	LU		N/A	N/A	N/A
3	AgPower Jerome LLC - Double A Digester	LU		N/A	N/A	N/A
4	Allan Ravenscroft/Malad River	LU	-	N/A	N/A	N/A
5	Baker City Hydro	LU		N/A	N/A	N/A
6	Bannock County, Idaho	LU		N/A	N/A	N/A
7	Bennett Creek Wind Farm	LU		N/A	N/A	N/A
8	Benson Creek Wind Farm	LU		N/A	N/A	N/A
9	Bettencourt DryCreek Biofactory	LU		N/A	N/A	N/A
10	Big Sky West Dairy Digester	LU		N/A	N/A	N/A
11	Black Canyon Bliss	LU		N/A	N/A	N/A
12	Blind Canyon Hydro	LU	-	N/A	N/A	N/A
13	Branchflower - Trout Company	LU	-	N/A	N/A	N/A
14	Burley Butte 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.
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)	
42,667				1,335,770		1,335,770	1
43,754				1,287,145		1,287,145	2
25,591				2,364,513		2,364,513	3
2,154			155,672	89,027		244,699	4
863				47,216		47,216	5
10,989				678,656		678,656	6
43,448				2,899,050		2,899,050	7
30,914				1,734,234		1,734,234	8
11,310				1,034,439		1,034,439	9
9,113				597,711		597,711	10
149				4,788		4,788	11
4,415				234,479		234,479	12
853				60,069		60,069	13
61,296				3,553,000		3,553,000	14
5,389,494	106,210	145,139	894,680	285,529,748	1,337,713	287,762,141	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	CAFCO Idaho Refuse Management LLC - SI	LU	-	N/A	N/A	N/A
2	Camp Reed Wind Park	LU	-	N/A	N/A	N/A
3	Cassia Wind Farm	LU	-	N/A	N/A	N/A
4	CCP OR Tenant 1, LLC - Grove	LU		N/A	N/A	N/A
5	CCP OR Tenant 1, LLC - Hyline	LU	-	N/A	N/A	N/A
6	CCP OR Tenant 1, LLC - Open Range	LU		N/A	N/A	N/A
7	CCP OR Tenant 1, LLC - Railroad	LU		N/A	N/A	N/A
8	CCP OR Tenant 1, LLC - Vale Air	LU		N/A	N/A	N/A
9	CCP OR Tenant 1, LLC - Thunderegg	LU		N/A	N/A	N/A
10	City of Hailey	LU		N/A	N/A	N/A
11	City of Pocatello	LU		N/A	N/A	N/A
12	Clear Springs Food Inc.	LU		N/A	N/A	N/A
13	Clifton E. Jenson - Birch Creek	LU		N/A	N/A	N/A
14	Cold Springs Windfarm, LLC	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.

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	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
8,533				279,512		279,512	1
66,824				5,499,676		5,499,676	2
24,869				1,376,188		1,376,188	3
13,314				805,812		805,812	4
20,273				1,233,789		1,233,789	5
22,543				1,366,000		1,366,000	6
10,064				610,482		610,482	7
21,769				1,321,022		1,321,022	8
22,246				1,348,243		1,348,243	9
				11		11	10
1,367				101,114		101,114	11
3,067				281,420		281,420	12
350			17,500	14,482		31,982	13
49,798				3,753,121		3,753,121	14
5,389,494	106,210	145,139	894,680	285,529,748	1,337,713	287,762,141	

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.

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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	College of Southern Idaho - Pristine S	LU	-	N/A	N/A	N/A
2	College of Southern Idaho - Pristine S	LU	-	N/A	N/A	N/A
3	Consolidated Hydro Inc. / Enel		-			
4	Barber Dam	LU	-	N/A	N/A	N/A
5	Dietrich Drop	LU	-	N/A	N/A	N/A
6	Lowline #2	LU	-	N/A	N/A	N/A
7	Rock Creek #2	LU	-	N/A	N/A	N/A
8	Crystal Springs Hydro	LU	-	N/A	N/A	N/A
9	Curry Cattle Company	LU	-	N/A	N/A	N/A
10	Cycle Horseshoe Bend Wind, LLC	LU	-	N/A	N/A	N/A
11	David R Snedigar	LU	-	N/A	N/A	N/A
12	Desert Meadow Windfarm	LU	-	N/A	N/A	N/A
13	Durbin Creek Windfarm	LU	-	N/A	N/A	N/A
14	Eightmile Hydro Corp	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)	
773				51,741		51,741	1
1,191				67,028		67,028	2
							3
12,220				611,007		611,007	4
14,240				798,246		798,246	5
9,750				517,398		517,398	6
5,172				278,136		278,136	7
11,123				756,672		756,672	8
715			12,326	50,830		63,156	9
17,636				1,151,359		1,151,359	10
1,309				92,301		92,301	11
60,140				4,526,150		4,526,150	12
27,900				1,566,269		1,566,269	13
1,525				102,666		102,666	14
5,389,494	106,210	145,139	894,680	285,529,748	1,337,713	287,762,141	

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	El Dorado Hydro - Elk Creek	LU	-	N/A	N/A	N/A
2	Faulkner Brothers Hydro Inc.	LU	-	N/A	N/A	N/A
3	Fisheries Development	LU	-	N/A	N/A	N/A
4	Fossil Gulch Wind	LU	-	N/A	N/A	N/A
5	G2 Energy Hidden Hollow	LU		N/A	N/A	N/A
6	Golden Valley Wind Park	LU	-	N/A	N/A	N/A
7	Grand View PV Solar Two, LLC	LU	-	N/A	N/A	N/A
8	Hammett Hill Windfarm, LLC	LU	-	N/A	N/A	N/A
9	Hazelton B Power Company	LU	-	N/A	N/A	N/A
10	High Mesa Energy	LU		N/A	N/A	N/A
11	H.K. Hydro Mud Creek S & S	LU		N/A	N/A	N/A
12	Horseshoe Bend Hydro	LU		N/A	N/A	N/A
13	Hot Springs Wind Farm	LU	-	N/A	N/A	N/A
14	ID Solar 1, LLC	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		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
3,243				222,178		222,178	1
3,874				301,135		301,135	2
398				7,478		7,478	3
26,383				1,586,278		1,586,278	4
21,891				1,522,224		1,522,224	5
32,708				1,954,173		1,954,173	6
183,049				10,147,556		10,147,556	7
56,987				4,296,705		4,296,705	8
22,839				1,664,222		1,664,222	9
96,497				5,012,868		5,012,868	10
1,642				88,990		88,990	11
44,462				3,170,792		3,170,792	12
38,169				2,545,676		2,545,676	13
97,313				5,024,382		5,024,382	14
5,389,494	106,210	145,139	894,680	285,529,748	1,337,713	287,762,141	

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	Idaho Winds - Sawtooth Wind Project	LU		N/A	N/A	N/A
2	J R Simplot Co.	IU	-	N/A	N/A	N/A
3	J.M. Miller/Sahko Hydro	LU	-	N/A	N/A	N/A
4	Jett Creek Windfarm	LU	-	N/A	N/A	N/A
5	John R LeMoyne	LU		N/A	N/A	N/A
6	Kasel & Witherspoon	LU		N/A	N/A	N/A
7	Kootenai Electric Cooperative - Fighti	LU		N/A	N/A	N/A
8	Koosh Inc. Geo Bon #2	LU		N/A	N/A	N/A
9	Koyle Hydro Inc.	LU	-	N/A	N/A	N/A
10	Lateral 10 Ventures	LU		N/A	N/A	N/A
11	Lemhi Hydro Power Co.- Schaffner	LU	-	N/A	N/A	N/A
12	Lime Wind	LU		N/A	N/A	N/A
13	Little Mac Power Co./Cedar Draw	LU	-	N/A	N/A	N/A
14	Little Wood River Irrigation District	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)	
55,628				4,719,183		4,719,183	1
63,821				3,262,801		3,262,801	2
1,365				114,427		114,427	3
29,466				1,661,284		1,661,284	4
640				35,889		35,889	5
333				29,843		29,843	6
14,092				1,164,246		1,164,246	7
3,817				284,219		284,219	8
3,411				322,698		322,698	9
7,122				449,534		449,534	10
1,378				104,276		104,276	11
6,076				471,255		471,255	12
6,118				393,244		393,244	13
6,500				452,743		452,743	14
5,389,494	106,210	145,139	894,680	285,529,748	1,337,713	287,762,141	

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.

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

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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	Magic Reservoir Hydro	LU	-	N/A	N/A	N/A
2	Mainline Windfarm	LU	-	N/A	N/A	N/A
3	Marco Rancher's Irrigation Inc.	LU	-	N/A	N/A	N/A
4	Marysville Hydro Partners- Falls River	LU	-	N/A	N/A	N/A
5	McCollum Enterprises -Canyon Springs	LU		N/A	N/A	N/A
6	Milner Dam Wind Park	LU	-	N/A	N/A	N/A
7	Mountain Home Solar I, LLC	LU	-	N/A	N/A	N/A
8	Mud Creek White Hydro, Inc	LU	-	N/A	N/A	N/A
9	Murphy Flat Power, LLC	LU	-	N/A	N/A	N/A
10	New Energy One - Rock Creek Dairy	LU	-	N/A	N/A	N/A
11	North Gooding Main, Hydro	LU	-	N/A	N/A	N/A
12	North Side Energy Company Inc					
13	Bypass Limited	LU		N/A	N/A	N/A
14	Hazelton A	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.
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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.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
20,025				1,071,801		1,071,801	1
57,625				4,340,576		4,340,576	2
3,004				210,083		210,083	3
58,588				3,972,617		3,972,617	4
483				11,320		11,320	5
56,611				3,297,786		3,297,786	6
47,038				1,514,391		1,514,391	7
545				37,254		37,254	8
45,755				1,470,327		1,470,327	9
6,224				571,174		571,174	10
4,769				403,906		403,906	11
							12
26,864				1,462,763		1,462,763	13
23,805				1,943,067		1,943,067	14
5,389,494	106,210	145,139	894,680	285,529,748	1,337,713	287,762,141	

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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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	Head of U Canal	LU		N/A	N/A	N/A
2	Orchard Ranch Solar, LLC	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	Pico Energy - B6 Anaerobic Digester	LU	-	N/A	N/A	N/A
10	Pigeon Cove Power	LU		N/A	N/A	N/A
11	Pilgrim Stage Station Wind Park	LU	-	N/A	N/A	N/A
12	Prospector Windfarm	LU		N/A	N/A	N/A
13	Reynolds Irrigation District	LU	-	N/A	N/A	N/A
14	Richard Kaster		-			
	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		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
4,273				385,028		385,028	1
47,739				1,408,696		1,408,696	2
37,867				2,271,688		2,271,688	3
							4
5,513				163,240		163,240	5
12,554				306,438		306,438	6
14,605				482,693		482,693	7
62,994				5,213,137		5,213,137	8
13,361				1,238,300		1,238,300	9
7,196			381,438	258,696		640,134	10
33,492				2,021,411		2,021,411	11
28,523				1,599,537		1,599,537	12
1,081				81,676		81,676	13
							14
5,389,494	106,210	145,139	894,680	285,529,748	1,337,713	287,762,141	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	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	Rockland Wind Project	LU		N/A	N/A	N/A
8	Ryegrass Windfarm	LU		N/A	N/A	N/A
9	Salmon Falls Wind Park	LU		N/A	N/A	N/A
10	Shingle Creek LLC	LU	-	N/A	N/A	N/A
11	Shorock Hydro Inc.					
12	Rock Creek #1	LU	-	N/A	N/A	N/A
13	Shoshone CSPP	LU		N/A	N/A	N/A
14	Shoshone #2	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)	
1,818				121,810		121,810	1
3,647				248,617		248,617	2
4,360				272,098		272,098	3
							4
1,614				148,576		148,576	5
3,933				237,987		237,987	6
245,271				16,450,830		16,450,830	7
54,292				4,095,751		4,095,751	8
65,013				3,865,361		3,865,361	9
1,032				62,569		62,569	10
							11
10,917			46,042	619,576		665,618	12
1,729				101,973		101,973	13
2,623				181,990		181,990	14
5,389,494	106,210	145,139	894,680	285,529,748	1,337,713	287,762,141	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	Simcoe Solar, LLC	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	-	N/A	N/A	N/A
5	Tasco - Nampa	OS		N/A	N/A	N/A
6	Tasco - Twin Falls	OS	-	N/A	N/A	N/A
7	Thousand Springs Wind Park	LU	-	N/A	N/A	N/A
8	Tiber Montana LLC - Tiber Dam	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/Arkoosh	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.
49,203				1,543,838		1,543,838	1
420				28,816		28,816	2
29,462				2,125,633		2,125,633	3
27,076			281,702	1,570,600		1,852,302	4
4							5
							6
32,515				1,948,244		1,948,244	7
26,020				1,573,871		1,573,871	8
29,883				1,789,982		1,789,982	9
76,235				5,509,555		5,509,555	10
9,118				543,767		543,767	11
59,244				4,433,876		4,433,876	12
758				51,861		51,861	13
3,821				285,736		285,736	14
5,389,494	106,210	145,139	894,680	285,529,748	1,337,713	287,762,141	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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

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

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

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

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

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

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

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

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	William Arkoosh- Littlewood River Ranc	LU		N/A	N/A	N/A
2	Willow Spring Windfarm	LU	-	N/A	N/A	N/A
3	Wilson Power Company	LU	-	N/A	N/A	N/A
4	Wood Hydro		-			
5	Black Canyon #3	LU		N/A	N/A	N/A
6	Jim Knight	LU	-	N/A	N/A	N/A
7	Mile 28	LU		N/A	N/A	N/A
8	Sagebrush	LU	-	N/A	N/A	N/A
9	Yahoo Creek Wind Park	LU		N/A	N/A	N/A
10	Scheduling Deviation					(3)
11	ADM Investor Services, Inc.	OS	WSPP	N/A	N/A	N/A
12	Arizona Public Service Co.	SF	WSPP	N/A	N/A	N/A
13	AVANGRID RENEWABLES, LLC	SF	WSPP	N/A	N/A	N/A
14	Avista Corp.	OS	T-12	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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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.
4,262				268,395		268,395	1
31,932				1,795,837		1,795,837	2
26,349				1,920,868		1,920,868	3
							4
255				18,578		18,578	5
724				56,083		56,083	6
4,105				273,739		273,739	7
953				70,513		70,513	8
65,458				5,381,784		5,381,784	9
5,268							10
					-6,474,592	-6,474,592	11
45,805				1,343,680		1,343,680	12
25,935				1,112,985		1,112,985	13
9					233	233	14
5,389,494	106,210	145,139	894,680	285,529,748	1,337,713	287,762,141	

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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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	Avista Corp.	SF	WSPP	N/A	N/A	N/A
2	Avista Corp.	OS	WSPP	N/A	N/A	N/A
3	Black Hills Power Inc.	SF	WSPP	N/A	N/A	N/A
4	Bonneville Power Administration	OS	WSPP	N/A	N/A	N/A
5	Bonneville Power Administration	SF	WSPP	N/A	N/A	N/A
6	Bonneville Power Administration	OS	WSPP	N/A	N/A	N/A
7	BP Energy Company	SF	WSPP	N/A	N/A	N/A
8	Brookfield Energy Marketing LP	SF	WSPP	N/A	N/A	N/A
9	California Independent System Operator	SF	CAISO	N/A	N/A	N/A
10	Calpine Energy Services, L.P.	SF	WSPP	N/A	N/A	N/A
11	Chelan Co PUD	OS	WSPP	N/A	N/A	N/A
12	Chelan Co PUD	SF	WSPP	N/A	N/A	N/A
13	Citigroup Energy Inc.	SF	WSPP	N/A	N/A	N/A
14	Citigroup Energy Inc.	OS	ISDA	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.
44,672				1,253,799		1,253,799	1
					294,557	294,557	2
210				1,140		1,140	3
77					1,953	1,953	4
62,855				1,633,252		1,633,252	5
					378,348	378,348	6
138,825				4,272,484		4,272,484	7
2,400				34,896		34,896	8
326,240				5,455,234		5,455,234	9
35,302				1,299,272		1,299,272	10
2					23	23	11
21,200				587,904		587,904	12
118,950				3,166,229		3,166,229	13
					-266,809	-266,809	14
5,389,494	106,210	145,139	894,680	285,529,748	1,337,713	287,762,141	

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	Clatskanie PUD	SF	WSPP	N/A	N/A	N/A
2	DTE Energy Trading, Inc.	SF	WSPP	N/A	N/A	N/A
3	EDF Trading North America, LLC	SF	WSPP	N/A	N/A	N/A
4	EDF Trading North America, LLC	OS	ISDA	N/A	N/A	N/A
5	Energy Keepers, Inc	SF	WSPP	N/A	N/A	N/A
6	Eugene Water & Electric Board	SF	WSPP	N/A	N/A	N/A
7	Exelon Generation Company, LLC	SF	WSPP	N/A	N/A	N/A
8	Grant CO Public Utility District #2 --	OS	WSPP	N/A	N/A	N/A
9	Gridforce Energy Management, LLC	OS	WSPP	N/A	N/A	N/A
10	J.Aron & Company LLC	SF	WSPP	N/A	N/A	N/A
11	J.Aron & Company LLC	OS	ISDA	N/A	N/A	N/A
12	Los Angeles Department of Water & Powe	SF	WSPP	N/A	N/A	N/A
13	Macquarie Energy LLC	SF	WSPP	N/A	N/A	N/A
14	Morgan Stanley Capital Group Inc.	SF	ISDA	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.
823				37,383		37,383	1
170				3,619		3,619	2
172,946				4,572,033		4,572,033	3
					-532,194	-532,194	4
5,681				115,453		115,453	5
7,620				207,180		207,180	6
39,843				1,143,073		1,143,073	7
7					195	195	8
4					160	160	9
30,800				807,936		807,936	10
					-554,156	-554,156	11
126				3,647		3,647	12
8,505				149,514		149,514	13
43,402				1,131,853		1,131,853	14
5,389,494	106,210	145,139	894,680	285,529,748	1,337,713	287,762,141	

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	Nevada Power Company, dba NV Energy	SF	WSPP	N/A	N/A	N/A
2	NorthWestern Energy	OS	T-7	N/A	N/A	N/A
3	NorthWestern Energy	SF	WSPP	N/A	N/A	N/A
4	NorthWestern Energy (Transmission)	OS	WSPP	N/A	N/A	N/A
5	PacifiCorp	OS	T-13	N/A	N/A	N/A
6	PacifiCorp	SF	WSPP	N/A	N/A	N/A
7	PacifiCorp Inc.	OS	WSPP	N/A	N/A	N/A
8	Portland General Electric Company	OS	T-14	N/A	N/A	N/A
9	Portland General Electric Company	SF	WSPP	N/A	N/A	N/A
10	Portland General Electric Company	OS		N/A	N/A	N/A
11	Powerex Corp.	SF	WSPP	N/A	N/A	N/A
12	Public Service Company of Colorado	SF	WSPP	N/A	N/A	N/A
13	Puget Sound Energy, Inc.	OS	T-9	N/A	N/A	N/A
14	Puget Sound Energy, 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.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
8,203				341,055		341,055	1
6					152	152	2
2,434				45,884		45,884	3
3					81	81	4
70					1,827	1,827	5
23,879				749,649		749,649	6
					3,638	3,638	7
19					487	487	8
55,071				607,322		607,322	9
					986,398	986,398	10
39,914				2,185,463		2,185,463	11
77,400				3,624,346		3,624,346	12
20					498	498	13
103,816				3,536,977		3,536,977	14
5,389,494	106,210	145,139	894,680	285,529,748	1,337,713	287,762,141	

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	Raft River Energy I LLC	LU	-	N/A	N/A	N/A
2	Rainbow Energy Marketing Corporation	SF	WSPP	N/A	N/A	N/A
3	Salt River Project	SF	WSPP	N/A	N/A	N/A
4	Seattle City Light	OS	WSPP	N/A	N/A	N/A
5	Seattle City Light	SF	WSPP	N/A	N/A	N/A
6	Shell Energy North America (US), L.P.	SF	WSPP	N/A	N/A	N/A
7	Sierra Pacific Power Co., dba NV Energ	OS	T-55	N/A	N/A	N/A
8	Snohomish County PUD	SF	WSPP	N/A	N/A	N/A
9	Tacoma Power	SF	WSPP	N/A	N/A	N/A
10	The Energy Authority, Inc.	SF	WSPP	N/A	N/A	N/A
11	TransAlta Energy Marketing (U.S.) Inc.	SF	WSPP	N/A	N/A	N/A
12	Tucson Electric Power Company	SF	WSPP	N/A	N/A	N/A
13	Westar Energy, Inc.	OS	WSPP	N/A	N/A	N/A
14	Westar Energy, 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.
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)	
83,122				5,669,475		5,669,475	1
420				20,030		20,030	2
164,000				4,907,732		4,907,732	3
7					154	154	4
22,047				741,597		741,597	5
39,770				1,070,258		1,070,258	6
40					1,059	1,059	7
2,610				101,845		101,845	8
3,039				75,210		75,210	9
2,157				36,931		36,931	10
86,850				4,564,480		4,564,480	11
2,524				69,984		69,984	12
1,071					42,304	42,304	13
1,213				45,482		45,482	14
5,389,494	106,210	145,139	894,680	285,529,748	1,337,713	287,762,141	

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	Telocaset Wind Power Partners LLC	LU	APP-A	N/A	N/A	N/A
2	Neal Hot Springs Unit #1	LU	-	N/A	N/A	N/A
3	Oregon Solar Customers	OS	-	N/A	N/A	N/A
4	Avista Corp.	EX	-			
5	Bonneville Power Administration	EX	-			
6	NorthWestern Energy	EX	-			
7	PacifiCorp Inc.	EX	-			
8	Sierra Pacific Power Co., dba NV Energ	EX	-			
9	Clatskanie PUD	EX	153			
10	Acctg Valuation of Clatskanie PUD	OS	0	N/A	N/A	N/A
11	Demand Response Avoided Energy	OS	-	N/A	N/A	N/A
12						
13						
14						
	Total					

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
314,813				19,741,403		19,741,403	1
176,491				20,234,669		20,234,669	2
779					17,879	17,879	3
	18						4
	20,261						5
		87					6
	8,687	106,060					7
		2,792					8
	77,244	36,200					9
					283,788	283,788	10
					7,151,730	7,151,730	11
							12
							13
							14
5,389,494	106,210	145,139	894,680	285,529,748	1,337,713	287,762,141	

Schedule Page: 326.3 Line No.: 9 Column: b
Ida West, a subsidiary of IdaCorp (Idaho Power Company's parent company), has partial ownership of this project.

Schedule Page: 326.5 Line No.: 4 Column: b
Ida West, a subsidiary of IdaCorp (Idaho Power Company's parent company), has partial ownership of this project.

Schedule Page: 326.8 Line No.: 3 Column: b
Ida West, a subsidiary of IdaCorp (Idaho Power Company's parent company), has partial ownership of this project.

Schedule Page: 326.8 Line No.: 5 Column: b
Non Firm Purchases

Schedule Page: 326.8 Line No.: 6 Column: b
Non Firm Purchases

Schedule Page: 326.9 Line No.: 3 Column: b
Ida West, a subsidiary of IdaCorp (Idaho Power Company's parent company), has partial ownership of this project.

Schedule Page: 326.9 Line No.: 11 Column: b
ADM Investor Services, Inc Futures Account Document, dated May 5, 2015

Schedule Page: 326.9 Line No.: 14 Column: b
Spinning or Operating Reserves

Schedule Page: 326.10 Line No.: 2 Column: b
Financial Transmission Losses

Schedule Page: 326.10 Line No.: 4 Column: b
Spinning or Operating Reserves

Schedule Page: 326.10 Line No.: 6 Column: b
Financial Transmission Losses

Schedule Page: 326.10 Line No.: 11 Column: b
Spinning or Operating Reserves

Schedule Page: 326.10 Line No.: 14 Column: b
ISDA Master Agreement With Citigroup, dated March 7, 2011

Schedule Page: 326.11 Line No.: 4 Column: b
ISDA Master Agreement With EDF Trading North America, LLC, dated October 25, 2012

Schedule Page: 326.11 Line No.: 8 Column: b
Spinning or Operating Reserves

Schedule Page: 326.11 Line No.: 9 Column: b
Spinning or Operating Reserves

Schedule Page: 326.11 Line No.: 11 Column: b
ISDA Master Agreement With J.Aron & Company LLC, dated April 30, 2014

Schedule Page: 326.12 Line No.: 2 Column: b
Spinning or Operating Reserves

Schedule Page: 326.12 Line No.: 4 Column: b
Spinning or Operating Reserves

Schedule Page: 326.12 Line No.: 5 Column: b
Spinning or Operating Reserves

Schedule Page: 326.12 Line No.: 7 Column: b
Financial Transmission Losses

Schedule Page: 326.12 Line No.: 8 Column: b
Spinning or Operating Reserves

Schedule Page: 326.12 Line No.: 10 Column: b
Operating agreement with Portland General Electric to still provide power if Boardman Power Plant offline - Boardman Assured

Schedule Page: 326.12 Line No.: 13 Column: b
Spinning or Operating Reserves

Schedule Page: 326.13 Line No.: 4 Column: b

Spinning or Operating Reserves

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

Spinning or Operating Reserves

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

Spinning or Operating Reserves

Schedule Page: 326.14 Line No.: 3 Column: b

Schedule 88 Oregon Solar

Schedule Page: 326.14 Line No.: 4 Column: b

Physical Transmission Losses

Schedule Page: 326.14 Line No.: 5 Column: b

Physical Transmission Losses

Schedule Page: 326.14 Line No.: 6 Column: b

Physical Transmission Losses

Schedule Page: 326.14 Line No.: 7 Column: b

Physical Transmission Losses

Schedule Page: 326.14 Line No.: 8 Column: b

Physical Transmission Losses

Schedule Page: 326.14 Line No.: 9 Column: b

Energy exchange between Clatskanie PUD and Idaho Power Company at Arrowrock Dam

Schedule Page: 326.14 Line No.: 10 Column: b

Energy exchange between Clatskanie PUD and Idaho Power Company at Arrowrock Dam

Schedule Page: 326.14 Line No.: 11 Column: b

Incentive program for customers to reduce demand during peak hours

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Bonneville Power Administration - OTEC	Bonneville Power Administration	Oregon Trails Electric Co-op	FNO
2	Bonneville Power Administration - USBR	Bonneville Power Administration	United States Bureau of Reclamati	FNO
3	Bonneville Power Administration - PF	Bonneville Power Administration	Priority Firm Customers	FNO
4	Milner Irrigation District	United States Bureau of Reclamati	Milner Irrigation District	OLF
5	Morgan Stanley Capital Group Inc.	Seattle City Light	Bonneville Power Administration	OS
6	PacifiCorp	PacifiCorp West	PacifiCorp West	FNO
7	United States Bureau of Indian Affairs	Bonneville Power Administration	United States Bureau of Indian Af	OS
8	Cycle Horseshoe Bend Wind, LLC	PacifiCorp East	PacifiCorp East	OS
9	Cycle Horseshoe Bend Wind, LLC	PacifiCorp East	PacifiCorp East	OS
10				
11	PacifiCorp Inc.	PacifiCorp East	Bonneville Power Administration	LFP
12	PacifiCorp Inc.	PacifiCorp East	PacifiCorp West	LFP
13	PacifiCorp Inc.	PacifiCorp East	PacifiCorp West	LFP
14	Morgan Stanley Capital Group Inc.	Idaho Power Company	Bonneville Power Administration	LFP
15	Bonneville Power Administration	PacifiCorp West	PacifiCorp East	LFP
16	Bonneville Power Administration	PacifiCorp West	PacifiCorp East	LFP
17				
18	Avangrid Renewables, LLC	PacifiCorp East	Bonneville Power Administration	NF
19	Avangrid Renewables, LLC	PacifiCorp East	Sierra Pacific Power	NF
20	Avangrid Renewables, LLC	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
21	Avangrid Renewables, LLC	Bonneville Power Administration	PacifiCorp East	NF
22	Avangrid Renewables, LLC	Bonneville Power Administration	Sierra Pacific Power	NF
23	Avangrid Renewables, LLC	Avista	PacifiCorp East	NF
24	Avangrid Renewables, LLC	Avista	Sierra Pacific Power	NF
25	Avangrid Renewables, LLC	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
26	Avangrid Renewables, LLC	Sierra Pacific Power	Bonneville Power Administration	NF
27	Avangrid Renewables, LLC	PacifiCorp West	PacifiCorp East	NF
28	Avista Corporation	Avista	PacifiCorp East	NF
29	Avista Corporation	Avista	Sierra Pacific Power	NF
30	Avista Corporation	Sierra Pacific Power	Avista	NF
31	Black Hills Power	PacifiCorp East	PacifiCorp East	NF
32	Black Hills Power	PacifiCorp East	Sierra Pacific Power	NF
33	Black Hills Power	Bonneville Power Administration	PacifiCorp East	NF
34	Black Hills Power	Bonneville Power Administration	PacifiCorp East	NF
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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.
9				332,530	332,530	1
9				241,422	241,422	2
9				1,335,909	1,335,909	3
Legacy	Minidoka, Idaho	Various in Idaho		7,985	7,985	4
4				349,894	349,894	5
9				2,000	2,000	6
Legacy	LaGrande, Oregon	Various in Idaho		16,612	16,612	7
5/6	BRDY	IPCOEAST		3,902	3,902	8
5/6	JEFF	IPCOEAST		13,115	13,115	9
						10
7/8	BORA	LAGRANDE		537,597	537,597	11
7/8	KPRT	HURR		342,844	342,844	12
7/8	BORA	HURR		574,326	574,326	13
7/8	LYPK	LAGRANDE		3,710	3,710	14
7/8	M500	KPRT		132,746	132,746	15
7/8	SMLK	KPRT		274,426	274,426	16
						17
7/8	BORA	LAGRANDE		242	242	18
7/8	BORA	M345		107	107	19
7/8	BPAT.NWMT	M345		380	380	20
7/8	LAGRANDE	BORA		980	980	21
7/8	LAGRANDE	M345		2,700	2,700	22
7/8	LOLO	BORA		200	200	23
7/8	LOLO	M345		13	13	24
7/8	M345	BPAT.NWMT		132	132	25
7/8	M345	LAGRANDE		3,191	3,191	26
7/8	SMLK	BORA		171	171	27
7/8	LOLO	BRDY		785	785	28
7/8	LOLO	M345		488	488	29
7/8	M345	LOLO		13	13	30
7/8	JBSN	BORA		140	140	31
7/8	JBSN	M345		30	30	32
7/8	LAGRANDE	BORA		137	137	33
7/8	LAGRANDE	JBSN		128	128	34
			0	**7,243,160**	**7,243,160**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	Black Hills Power	PacifiCorp West	PacifiCorp East	NF
2	Bonneville Power Administration	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
3	Bonneville Power Administration	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
4	Bonneville Power Administration	NorthWestern/PacifiCorp East	Sierra Pacific Power	SFP
5	Bonneville Power Administration	PacifiCorp East	Sierra Pacific Power	NF
6	Bonneville Power Administration	Bonneville Power Administration	PacifiCorp East	NF
7	Bonneville Power Administration	Bonneville Power Administration	PacifiCorp East	NF
8	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	NF
9	Bonneville Power Administration	Bonneville Power Administration	Sierra Pacific Power	NF
10	Bonneville Power Administration	Bonneville Power Administration	Bonneville Power Administration	NF
11	Bonneville Power Administration	Avista	Bonneville Power Administration	NF
12	Bonneville Power Administration	Avista	Sierra Pacific Power	NF
13	Bonneville Power Administration	Sierra Pacific Power	PacifiCorp East	NF
14	Bonneville Power Administration	PacifiCorp West	Sierra Pacific Power	NF
15	Bonneville Power Administration	PacifiCorp West	PacifiCorp East	NF
16	Bonneville Power Administration	PacifiCorp West	PacifiCorp East	SFP
17	Bonneville Power Administration	PacifiCorp West	PacifiCorp East	SFP
18	Bonneville Power Administration	PacifiCorp West	Sierra Pacific Power	SFP
19	Brookfield Energy Marketing LP	PacifiCorp East	Sierra Pacific Power	SFP
20	CWP Energy Inc.	PacifiCorp East	Sierra Pacific Power	NF
21	EDF Trading North America, LLC	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
22	EDF Trading North America, LLC	PacifiCorp East	Bonneville Power Administration	NF
23	EDF Trading North America, LLC	PacifiCorp East	Bonneville Power Administration	NF
24	EDF Trading North America, LLC	Bonneville Power Administration	PacifiCorp East	NF
25	Energy Keepers, Inc.	PacifiCorp East	Sierra Pacific Power	SFP
26	Energy Keepers, Inc.	Avista	PacifiCorp East	NF
27	Macquarie Energy, LLC	PacifiCorp East	PacifiCorp East	NF
28	Macquarie Energy, LLC	PacifiCorp East	PacifiCorp East	SFP
29	Macquarie Energy, LLC	PacifiCorp East	Sierra Pacific Power	NF
30	Macquarie Energy, LLC	PacifiCorp East	Sierra Pacific Power	SFP
31	Macquarie Energy, LLC	PacifiCorp East	Sierra Pacific Power	SFP
32	Macquarie Energy, LLC	PacifiCorp East	Sierra Pacific Power	NF
33	Macquarie Energy, LLC	PacifiCorp East	Sierra Pacific Power	NF
34	Macquarie Energy, LLC	Sierra Pacific Power	PacifiCorp East	NF
	TOTAL			

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

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

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
7/8	M500	BRDY		5	5	1
7/8	BPAT.NWMT	BORA		7,126	7,126	2
7/8	BPAT.NWMT	M345		101	101	3
7/8	BPAT.NWMT	M345		9,893	9,893	4
7/8	BRDY	M345		61	61	5
7/8	LAGRANDE	BORA		183	183	6
7/8	LAGRANDE	KPRT		25	25	7
7/8	LAGRANDE	LAGRANDE		1,728	1,728	8
7/8	LAGRANDE	M345		5,662	5,662	9
7/8	LAGRANDE	OTEC		20	20	10
7/8	LOLO	LAGRANDE		1,320	1,320	11
7/8	LOLO	M345		257	257	12
7/8	M345	BORA		4	4	13
7/8	M500	M345		121	121	14
7/8	SMLK	BORA		149	149	15
7/8	SMLK	BORA		81,075	81,075	16
7/8	SMLK	BRDY		195	195	17
7/8	SMLK	M345		97,533	97,533	18
7/8	BRDY	M345		42,698	42,698	19
7/8	BRDY	M345		1,483	1,483	20
7/8	BPAT.NWMT	LAGRANDE		1,150	1,150	21
7/8	BRDY	LAGRANDE		1,826	1,826	22
7/8	JEFF	LAGRANDE		72	72	23
7/8	LAGRANDE	BRDY		57	57	24
7/8	BRDY	M345		32,023	32,023	25
7/8	LOLO	BRDY		2	2	26
7/8	BRDY	BORA		115	115	27
7/8	BRDY	BORA		2,023	2,023	28
7/8	BRDY	M345		214	214	29
7/8	BRDY	M345		4,286	4,286	30
7/8	GSHN	M345		160	160	31
7/8	JBSN	M345		27	27	32
7/8	JEFF	M345		250	250	33
7/8	M345	BORA		529	529	34
			0	**7,243,160**	**7,243,160**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	Macquarie Energy, LLC	Sierra Pacific Power	PacifiCorp East	NF
2	Mag Energy Solutions	PacifiCorp East	Sierra Pacific Power	NF
3	Mag Energy Solutions	PacifiCorp East	Sierra Pacific Power	NF
4	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
5	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
6	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
7	Morgan Stanley Capital Group Inc.	PacifiCorp East	Bonneville Power Administration	NF
8	Morgan Stanley Capital Group Inc.	PacifiCorp East	Bonneville Power Administration	SFP
9	Morgan Stanley Capital Group Inc.	PacifiCorp East	Avista	NF
10	Morgan Stanley Capital Group Inc.	PacifiCorp East	Sierra Pacific Power	NF
11	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
12	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
13	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
14	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
15	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
16	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
17	Morgan Stanley Capital Group Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	SFP
18	Morgan Stanley Capital Group Inc.	PacifiCorp East	NorthWestern/PacifiCorp East	NF
19	Morgan Stanley Capital Group Inc.	PacifiCorp East	PacifiCorp East	NF
20	Morgan Stanley Capital Group Inc.	PacifiCorp East	PacifiCorp East	SFP
21	Morgan Stanley Capital Group Inc.	PacifiCorp East	NorthWestern/PacifiCorp East	NF
22	Morgan Stanley Capital Group Inc.	PacifiCorp East	Bonneville Power Administration	NF
23	Morgan Stanley Capital Group Inc.	PacifiCorp East	Avista	NF
24	Morgan Stanley Capital Group Inc.	PacifiCorp East	Sierra Pacific Power	NF
25	Morgan Stanley Capital Group Inc.	PacifiCorp East	Sierra Pacific Power	SFP
26	Morgan Stanley Capital Group Inc.	Idaho Power Company	NorthWestern/PacifiCorp East	NF
27	Morgan Stanley Capital Group Inc.	Idaho Power Company	NorthWestern/PacifiCorp East	NF
28	Morgan Stanley Capital Group Inc.	PacifiCorp East	PacifiCorp East	NF
29	Morgan Stanley Capital Group Inc.	PacifiCorp East	PacifiCorp East	SFP
30	Morgan Stanley Capital Group Inc.	PacifiCorp East	PacifiCorp East	NF
31	Morgan Stanley Capital Group Inc.	PacifiCorp East	Sierra Pacific Power	NF
32	Morgan Stanley Capital Group Inc.	PacifiCorp East	PacifiCorp East	NF
33	Morgan Stanley Capital Group Inc.	PacifiCorp East	PacifiCorp East	SFP
34	Morgan Stanley Capital Group Inc.	PacifiCorp East	PacifiCorp East	NF
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	M345	BRDY		259	259	1
7/8	BRDY	M345		14,055	14,055	2
7/8	JEFF	M345		14,903	14,903	3
7/8	AVAT.NWMT	BORA		45	45	4
7/8	AVAT.NWMT	LAGRANDE		739	739	5
7/8	AVAT.NWMT	M345		4,544	4,544	6
7/8	BORA	LAGRANDE		3,091	3,091	7
7/8	BORA	LAGRANDE		8,822	8,822	8
7/8	BORA	LOLO		400	400	9
7/8	BORA	M345		576	576	10
7/8	BPAT.NWMT	BORA		53	53	11
7/8	BPAT.NWMT	BORA		31,632	31,632	12
7/8	BPAT.NWMT	BRDY		20	20	13
7/8	BPAT.NWMT	BRDY		1,104	1,104	14
7/8	BPAT.NWMT	LAGRANDE		3,667	3,667	15
7/8	BPAT.NWMT	M345		9,184	9,184	16
7/8	BPAT.NWMT	M345		71,250	71,250	17
7/8	BRDY	AVAT.NWMT		50	50	18
7/8	BRDY	BORA		7,363	7,363	19
7/8	BRDY	BORA		4,483	4,483	20
7/8	BRDY	BPAT.NWMT		272	272	21
7/8	BRDY	LAGRANDE		13,864	13,864	22
7/8	BRDY	LOLO		83	83	23
7/8	BRDY	M345		34,407	34,407	24
7/8	BRDY	M345		85,747	85,747	25
7/8	IPCOGEN	AVAT.NWMT		14	14	26
7/8	IPCOGEN	BPAT.NWMT		20	20	27
7/8	JBSN	BORA		11,993	11,993	28
7/8	JBSN	BORA		5,213	5,213	29
7/8	JBSN	BRDY		10	10	30
7/8	JBSN	M345		613	613	31
7/8	JEFF	BORA		43,691	43,691	32
7/8	JEFF	BORA		2,254	2,254	33
7/8	JEFF	BRDY		1,466	1,466	34
			0	**7,243,160**	**7,243,160**	

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Morgan Stanley Capital Group Inc.	PacifiCorp East	Bonneville Power Administration	NF
2	Morgan Stanley Capital Group Inc.	PacifiCorp East	Sierra Pacific Power	NF
3	Morgan Stanley Capital Group Inc.	PacifiCorp East	Sierra Pacific Power	SFP
4	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	NorthWestern/PacifiCorp East	NF
5	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	PacifiCorp East	NF
6	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	PacifiCorp East	SFP
7	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	PacifiCorp East	NF
8	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	Sierra Pacific Power	NF
9	Morgan Stanley Capital Group Inc.	Bonneville Power Administration	Sierra Pacific Power	SFP
10	Morgan Stanley Capital Group Inc.	Avista	PacifiCorp East	NF
11	Morgan Stanley Capital Group Inc.	Avista	PacifiCorp East	SFP
12	Morgan Stanley Capital Group Inc.	Avista	PacifiCorp East	NF
13	Morgan Stanley Capital Group Inc.	Avista	Sierra Pacific Power	NF
14	Morgan Stanley Capital Group Inc.	Avista	Sierra Pacific Power	SFP
15	Morgan Stanley Capital Group Inc.	Idaho Power Company	NorthWestern/PacifiCorp East	NF
16	Morgan Stanley Capital Group Inc.	Idaho Power Company	PacifiCorp East	NF
17	Morgan Stanley Capital Group Inc.	Idaho Power Company	PacifiCorp East	SFP
18	Morgan Stanley Capital Group Inc.	Idaho Power Company	NorthWestern/PacifiCorp East	NF
19	Morgan Stanley Capital Group Inc.	Idaho Power Company	PacifiCorp East	NF
20	Morgan Stanley Capital Group Inc.	Idaho Power Company	Avista	NF
21	Morgan Stanley Capital Group Inc.	Idaho Power Company	Sierra Pacific Power	NF
22	Morgan Stanley Capital Group Inc.	Idaho Power Company	Sierra Pacific Power	SFP
23	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
24	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	PacifiCorp East	NF
25	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
26	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	PacifiCorp East	NF
27	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	Bonneville Power Administration	NF
28	Morgan Stanley Capital Group Inc.	Sierra Pacific Power	Avista	NF
29	Morgan Stanley Capital Group Inc.	Idaho Power Company	NorthWestern/PacifiCorp East	NF
30	Morgan Stanley Capital Group Inc.	PacifiCorp West	PacifiCorp East	NF
31	Morgan Stanley Capital Group Inc.	PacifiCorp West	PacifiCorp East	SFP
32	Morgan Stanley Capital Group Inc.	PacifiCorp West	Sierra Pacific Power	NF
33	Morgan Stanley Capital Group Inc.	Idaho Power Company	PacifiCorp East	NF
34	Morgan Stanley Capital Group Inc.	Idaho Power Company	PacifiCorp East	NF
	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	JEFF	LAGRANDE		322	322	1
7/8	JEFF	M345		53,922	53,922	2
7/8	JEFF	M345		1,404	1,404	3
7/8	LAGRANDE	AVAT.NWMT		316	316	4
7/8	LAGRANDE	BORA		12,932	12,932	5
7/8	LAGRANDE	BORA		10,699	10,699	6
7/8	LAGRANDE	BRDY		3,419	3,419	7
7/8	LAGRANDE	M345		110,211	110,211	8
7/8	LAGRANDE	M345		90	90	9
7/8	LOLO	BORA		33,699	33,699	10
7/8	LOLO	BORA		5,439	5,439	11
7/8	LOLO	BRDY		282	282	12
7/8	LOLO	M345		283,043	283,043	13
7/8	LOLO	M345		153,240	153,240	14
7/8	LYPK	AVAT.NWMT		547	547	15
7/8	LYPK	BORA		1,820	1,820	16
7/8	LYPK	BORA		31,373	31,373	17
7/8	LYPK	BPAT.NWMT		1,239	1,239	18
7/8	LYPK	BRDY		2,420	2,420	19
7/8	LYPK	LOLO		500	500	20
7/8	LYPK	M345		4,194	4,194	21
7/8	LYPK	M345		302,387	302,387	22
7/8	M345	AVAT.NWMT		8	8	23
7/8	M345	BORA		242	242	24
7/8	M345	BPAT.NWMT		3,152	3,152	25
7/8	M345	BRDY		2,967	2,967	26
7/8	M345	LAGRANDE		33,775	33,775	27
7/8	M345	LOLO		10,332	10,332	28
7/8	OBBLPR	AVAT.NWMT		13	13	29
7/8	SMLK	BORA		248,832	248,832	30
7/8	SMLK	BORA		2,280	2,280	31
7/8	SMLK	M345		1,980	1,980	32
7/8	WALLAWALLA	BORA		156,066	156,066	33
7/8	WALLAWALLA	BRDY		23	23	34
			0	**7,243,160**	**7,243,160**	

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Morgan Stanley Capital Group Inc.	Idaho Power Company	Sierra Pacific Power	NF
2	Nevada Power Company	PacifiCorp East	Sierra Pacific Power	NF
3	Nevada Power Company	PacifiCorp East	Sierra Pacific Power	SFP
4	Nevada Power Company	Avista	Sierra Pacific Power	SFP
5	Nevada Power Company	Sierra Pacific Power	Bonneville Power Administration	NF
6	Northwestern Energy	PacifiCorp East	Bonneville Power Administration	NF
7	PacifiCorp Inc.	PacifiCorp East	Idaho Power Company	NF
8	PacifiCorp Inc.	PacifiCorp East	Avista	NF
9	PacifiCorp Inc.	PacifiCorp East	Avista	SFP
10	PacifiCorp Inc.	PacifiCorp East	PacifiCorp East	NF
11	PacifiCorp Inc.	PacifiCorp East	PacifiCorp East	NF
12	PacifiCorp Inc.	PacifiCorp East	Bonneville Power Administration	NF
13	PacifiCorp Inc.	PacifiCorp East	Avista	NF
14	PacifiCorp Inc.	PacifiCorp East	NorthWestern/PacifiCorp East	NF
15	PacifiCorp Inc.	PacifiCorp West	PacifiCorp East	NF
16	PacifiCorp Inc.	PacifiCorp West	PacifiCorp East	NF
17	PacifiCorp Inc.	PacifiCorp East	Idaho Power Company	NF
18	PacifiCorp Inc.	PacifiCorp East	PacifiCorp East	NF
19	PacifiCorp Inc.	Bonneville Power Administration	PacifiCorp East	NF
20	PacifiCorp Inc.	Bonneville Power Administration	PacifiCorp East	NF
21	PacifiCorp Inc.	Bonneville Power Administration	Sierra Pacific Power	NF
22	PacifiCorp Inc.	Avista	PacifiCorp East	NF
23	PacifiCorp Inc.	Avista	PacifiCorp East	NF
24	PacifiCorp Inc.	Avista	Bonneville Power Administration	NF
25	PacifiCorp Inc.	PacifiCorp West	PacifiCorp East	NF
26	PacifiCorp Inc.	PacifiCorp West	PacifiCorp East	NF
27	PacifiCorp Inc.	Idaho Power Company	PacifiCorp East	NF
28	PacifiCorp Inc.	Idaho Power Company	PacifiCorp East	NF
29	PacifiCorp Inc.	Idaho Power Company	Bonneville Power Administration	NF
30	Portland General Electric	PacifiCorp East	Bonneville Power Administration	NF
31	Portland General Electric	PacifiCorp East	Bonneville Power Administration	SFP
32	Portland General Electric	PacifiCorp East	Bonneville Power Administration	NF
33	Portland General Electric	PacifiCorp East	Bonneville Power Administration	SFP
34	Portland General Electric	PacifiCorp East	Bonneville Power Administration	NF
	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	WALLAWALLA	M345		236	236	1
7/8	BRDY	M345		1,632	1,632	2
7/8	BRDY	M345		2,688	2,688	3
7/8	LOLO	M345		1,120	1,120	4
7/8	M345	LAGRANDE		150	150	5
7/8	BRDY	LAGRANDE		165	165	6
7/8	BORA	IPCO		4	4	7
7/8	BORA	LOLO		150	150	8
7/8	BORA	LOLO		255,418	255,418	9
7/8	BRDY	BORA		780	780	10
7/8	BRDY	BRDY		66	66	11
7/8	BRDY	LAGRANDE		4,748	4,748	12
7/8	BRDY	LOLO		152	152	13
7/8	BRDY	MLCK		4,446	4,446	14
7/8	HURR	BORA		1,889	1,889	15
7/8	HURR	BRDY		605	605	16
7/8	JEFF	BGSY		4,752	4,752	17
7/8	JEFF	BORA		1	1	18
7/8	LAGRANDE	BORA		3,634	3,634	19
7/8	LAGRANDE	BRDY		3,410	3,410	20
7/8	LAGRANDE	M345		49	49	21
7/8	LOLO	BORA		513	513	22
7/8	LOLO	BRDY		375	375	23
7/8	LOLO	LAGRANDE		434	434	24
7/8	SMLK	BORA		985	985	25
7/8	SMLK	BRDY		620	620	26
7/8	WALLAWALLA	BORA		2,440	2,440	27
7/8	WALLAWALLA	BRDY		2,848	2,848	28
7/8	WALLAWALLA	LAGRANDE		490	490	29
7/8	BORA	LAGRANDE		5	5	30
7/8	BORA	LAGRANDE		29,075	29,075	31
7/8	BRDY	LAGRANDE		69	69	32
7/8	BRDY	LAGRANDE		16,096	16,096	33
7/8	JBSN	LAGRANDE		2	2	34
			0	**7,243,160**	**7,243,160**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/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	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
2	Powerex Corporation	PacifiCorp East	NorthWestern/PacifiCorp East	NF
3	Powerex Corporation	PacifiCorp East	NorthWestern/PacifiCorp East	SFP
4	Powerex Corporation	PacifiCorp East	Bonneville Power Administration	NF
5	Powerex Corporation	PacifiCorp East	Bonneville Power Administration	SFP
6	Powerex Corporation	PacifiCorp East	Avista	SFP
7	Powerex Corporation	PacifiCorp East	Sierra Pacific Power	NF
8	Powerex Corporation	NorthWestern/PacifiCorp East	PacifiCorp East	NF
9	Powerex Corporation	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
10	Powerex Corporation	NorthWestern/PacifiCorp East	PacifiCorp East	NF
11	Powerex Corporation	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
12	Powerex Corporation	PacifiCorp East	PacifiCorp East	NF
13	Powerex Corporation	PacifiCorp East	NorthWestern/PacifiCorp East	SFP
14	Powerex Corporation	PacifiCorp East	PacifiCorp West	NF
15	Powerex Corporation	PacifiCorp East	Bonneville Power Administration	NF
16	Powerex Corporation	PacifiCorp East	Sierra Pacific Power	NF
17	Powerex Corporation	PacifiCorp East	PacifiCorp East	NF
18	Powerex Corporation	PacifiCorp West	PacifiCorp East	NF
19	Powerex Corporation	PacifiCorp West	PacifiCorp East	NF
20	Powerex Corporation	PacifiCorp East	PacifiCorp East	NF
21	Powerex Corporation	PacifiCorp East	Bonneville Power Administration	NF
22	Powerex Corporation	PacifiCorp East	Sierra Pacific Power	NF
23	Powerex Corporation	Bonneville Power Administration	PacifiCorp East	NF
24	Powerex Corporation	Bonneville Power Administration	PacifiCorp East	NF
25	Powerex Corporation	Bonneville Power Administration	Sierra Pacific Power	NF
26	Powerex Corporation	Avista	PacifiCorp East	NF
27	Powerex Corporation	Avista	PacifiCorp East	NF
28	Powerex Corporation	Avista	Sierra Pacific Power	NF
29	Powerex Corporation	Sierra Pacific Power	PacifiCorp East	NF
30	Powerex Corporation	Sierra Pacific Power	Bonneville Power Administration	NF
31	Powerex Corporation	PacifiCorp West	PacifiCorp East	NF
32	Powerex Corporation	PacifiCorp West	PacifiCorp East	NF
33	Powerex Corporation	PacifiCorp West	PacifiCorp East	NF
34	Powerex Corporation	Idaho Power Company	PacifiCorp East	NF
	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	AVAT.NWMT	LAGRANDE		471	471	1
7/8	BORA	BPAT.NWMT		50	50	2
7/8	BORA	BPAT.NWMT		102	102	3
7/8	BORA	LAGRANDE		6,736	6,736	4
7/8	BORA	LAGRANDE		18	18	5
7/8	BORA	LOLO		538	538	6
7/8	BORA	M345		306	306	7
7/8	BPAT.NWMT	BORA		35	35	8
7/8	BPAT.NWMT	BORA		100	100	9
7/8	BPAT.NWMT	BRDY		42	42	10
7/8	BPAT.NWMT	LAGRANDE		33	33	11
7/8	BRDY	BORA		144	144	12
7/8	BRDY	BPAT.NWMT		20	20	13
7/8	BRDY	HURR		60	60	14
7/8	BRDY	LAGRANDE		2,587	2,587	15
7/8	BRDY	M345		1,189	1,189	16
7/8	GSHN	BRDY		36	36	17
7/8	HURR	BORA		31	31	18
7/8	HURR	BRDY		4	4	19
7/8	JEFF	BORA		184	184	20
7/8	JEFF	LAGRANDE		252	252	21
7/8	JEFF	M345		8	8	22
7/8	LAGRANDE	BORA		9,217	9,217	23
7/8	LAGRANDE	BRDY		2,258	2,258	24
7/8	LAGRANDE	M345		1,693	1,693	25
7/8	LOLO	BORA		136	136	26
7/8	LOLO	BRDY		45	45	27
7/8	LOLO	M345		122	122	28
7/8	M345	BORA		11	11	29
7/8	M345	LAGRANDE		878	878	30
7/8	POP	BORA		122	122	31
7/8	SMLK	BORA		2,360	2,360	32
7/8	SMLK	BRDY		328	328	33
7/8	WALLAWALLA	BORA		2,580	2,580	34
			0	**7,243,160**	**7,243,160**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	Idaho Power Company	PacifiCorp East	NF
2	Powerex Corporation	Idaho Power Company	Sierra Pacific Power	NF
3	Rainbow Energy Marketing Coporation	PacifiCorp East	NorthWestern/PacifiCorp East	SFP
4	Rainbow Energy Marketing Coporation	PacifiCorp East	Bonneville Power Administration	NF
5	Rainbow Energy Marketing Coporation	PacifiCorp East	Bonneville Power Administration	SFP
6	Rainbow Energy Marketing Coporation	PacifiCorp East	Avista	NF
7	Rainbow Energy Marketing Coporation	NorthWestern/PacifiCorp East	PacifiCorp East	SFP
8	Rainbow Energy Marketing Coporation	NorthWestern/PacifiCorp East	Sierra Pacific Power	SFP
9	Rainbow Energy Marketing Coporation	PacifiCorp East	Bonneville Power Administration	SFP
10	Rainbow Energy Marketing Coporation	PacifiCorp East	PacifiCorp East	NF
11	Rainbow Energy Marketing Coporation	PacifiCorp East	PacifiCorp East	SFP
12	Rainbow Energy Marketing Coporation	Avista	PacifiCorp East	NF
13	Rainbow Energy Marketing Coporation	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
14	Rainbow Energy Marketing Coporation	Sierra Pacific Power	Bonneville Power Administration	NF
15	Shell Energy North America (US), L.P.	PacifiCorp East	NorthWestern/PacifiCorp East	NF
16	Shell Energy North America (US), L.P.	PacifiCorp East	Bonneville Power Administration	NF
17	Shell Energy North America (US), L.P.	PacifiCorp East	Avista	NF
18	Shell Energy North America (US), L.P.	PacifiCorp East	Sierra Pacific Power	NF
19	Shell Energy North America (US), L.P.	PacifiCorp East	Sierra Pacific Power	SFP
20	Shell Energy North America (US), L.P.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
21	Shell Energy North America (US), L.P.	NorthWestern/PacifiCorp East	PacifiCorp East	NF
22	Shell Energy North America (US), L.P.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
23	Shell Energy North America (US), L.P.	PacifiCorp East	NorthWestern/PacifiCorp East	NF
24	Shell Energy North America (US), L.P.	PacifiCorp East	Bonneville Power Administration	NF
25	Shell Energy North America (US), L.P.	PacifiCorp East	Avista	NF
26	Shell Energy North America (US), L.P.	PacifiCorp East	Sierra Pacific Power	NF
27	Shell Energy North America (US), L.P.	PacifiCorp East	Sierra Pacific Power	SFP
28	Shell Energy North America (US), L.P.	PacifiCorp East	PacifiCorp East	NF
29	Shell Energy North America (US), L.P.	PacifiCorp East	Bonneville Power Administration	NF
30	Shell Energy North America (US), L.P.	PacifiCorp East	Bonneville Power Administration	NF
31	Shell Energy North America (US), L.P.	PacifiCorp East	Sierra Pacific Power	NF
32	Shell Energy North America (US), L.P.	Bonneville Power Administration	PacifiCorp East	NF
33	Shell Energy North America (US), L.P.	Bonneville Power Administration	PacifiCorp East	NF
34	Shell Energy North America (US), L.P.	Bonneville Power Administration	PacifiCorp East	SFP
	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	WALLAWALLA	BRDY		363	363	1
7/8	WALLAWALLA	M345		1,823	1,823	2
7/8	BORA	BPAT.NWMT		413	413	3
7/8	BORA	LAGRANDE		312	312	4
7/8	BORA	LAGRANDE		5,980	5,980	5
7/8	BORA	LOLO		425	425	6
7/8	BPAT.NWMT	BRDY		19,441	19,441	7
7/8	BPAT.NWMT	M345		2,678	2,678	8
7/8	BRDY	LAGRANDE		1,678	1,678	9
7/8	JEFF	BRDY		4,748	4,748	10
7/8	JEFF	BRDY		1,152	1,152	11
7/8	LOLO	BORA		330	330	12
7/8	M345	BPAT.NWMT		465	465	13
7/8	M345	LAGRANDE		2,902	2,902	14
7/8	BORA	BPAT.NWMT		45	45	15
7/8	BORA	LAGRANDE		3,815	3,815	16
7/8	BORA	LOLO		363	363	17
7/8	BORA	M345		400	400	18
7/8	BORA	M345		96	96	19
7/8	BPAT.NWMT	BORA		100	100	20
7/8	BPAT.NWMT	BRDY		108	108	21
7/8	BPAT.NWMT	M345		838	838	22
7/8	BRDY	BPAT.NWMT		136	136	23
7/8	BRDY	LAGRANDE		4,168	4,168	24
7/8	BRDY	LOLO		443	443	25
7/8	BRDY	M345		6,338	6,338	26
7/8	BRDY	M345		21,773	21,773	27
7/8	JBSN	BORA		637	637	28
7/8	JBSN	LAGRANDE		1,748	1,748	29
7/8	JEFF	LAGRANDE		25	25	30
7/8	JEFF	M345		400	400	31
7/8	LAGRANDE	BORA		24,412	24,412	32
7/8	LAGRANDE	BRDY		8,498	8,498	33
7/8	LAGRANDE	BRDY		638	638	34
			0	**7,243,160**	**7,243,160**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/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.	Bonneville Power Administration	PacifiCorp East	NF
2	Shell Energy North America (US), L.P.	Bonneville Power Administration	Sierra Pacific Power	NF
3	Shell Energy North America (US), L.P.	Avista	PacifiCorp East	NF
4	Shell Energy North America (US), L.P.	Avista	PacifiCorp East	NF
5	Shell Energy North America (US), L.P.	Avista	Sierra Pacific Power	NF
6	Shell Energy North America (US), L.P.	Avista	Sierra Pacific Power	SFP
7	Shell Energy North America (US), L.P.	Sierra Pacific Power	PacifiCorp East	NF
8	Shell Energy North America (US), L.P.	Sierra Pacific Power	NorthWestern/PacifiCorp East	NF
9	Shell Energy North America (US), L.P.	Sierra Pacific Power	Bonneville Power Administration	NF
10	Shell Energy North America (US), L.P.	Sierra Pacific Power	Avista	NF
11	Shell Energy North America (US), L.P.	PacifiCorp West	PacifiCorp East	NF
12	Shell Energy North America (US), L.P.	PacifiCorp West	Sierra Pacific Power	NF
13	Shell Energy North America (US), L.P.	Idaho Power Company	PacifiCorp East	NF
14	Shell Energy North America (US), L.P.	Idaho Power Company	PacifiCorp East	SFP
15	Shell Energy North America (US), L.P.	Idaho Power Company	PacifiCorp East	NF
16	Shell Energy North America (US), L.P.	Idaho Power Company	PacifiCorp East	SFP
17	Shell Energy North America (US), L.P.	Idaho Power Company	Sierra Pacific Power	NF
18	Shell Energy North America (US), L.P.	Idaho Power Company	Sierra Pacific Power	SFP
19	Tenaska Power Services	PacifiCorp East	Sierra Pacific Power	NF
20	Tenaska Power Services	PacifiCorp East	Sierra Pacific Power	NF
21	Tenaska Power Services	PacifiCorp East	Sierra Pacific Power	SFP
22	The Energy Authority, Inc.	PacifiCorp East	Bonneville Power Administration	NF
23	The Energy Authority, Inc.	Bonneville Power Administration	PacifiCorp East	NF
24	The Energy Authority, Inc.	Bonneville Power Administration	Sierra Pacific Power	NF
25	The Energy Authority, Inc.	Sierra Pacific Power	Bonneville Power Administration	NF
26	The Energy Authority, Inc.	PacifiCorp West	PacifiCorp East	NF
27	The Energy Authority, Inc.	PacifiCorp West	PacifiCorp East	NF
28	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp East	NorthWestern/PacifiCorp East	NF
29	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp East	Bonneville Power Administration	NF
30	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp East	Avista	NF
31	Transalta Energy Marketing (U.S.) Inc.	NorthWestern/PacifiCorp East	Bonneville Power Administration	NF
32	Transalta Energy Marketing (U.S.) Inc.	NorthWestern/PacifiCorp East	Sierra Pacific Power	NF
33	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp East	Bonneville Power Administration	NF
34	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp East	PacifiCorp East	NF
	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)	MegaWatt Hours Delivered (j)	Line No.
7/8	LAGRANDE	JBSN		912	912	1
7/8	LAGRANDE	M345		82,658	82,658	2
7/8	LOLO	BORA		1,587	1,587	3
7/8	LOLO	BRDY		6,262	6,262	4
7/8	LOLO	M345		106,523	106,523	5
7/8	LOLO	M345		63,459	63,459	6
7/8	M345	BORA		373	373	7
7/8	M345	BPAT.NWMT		231	231	8
7/8	M345	LAGRANDE		4,019	4,019	9
7/8	M345	LOLO		68	68	10
7/8	SMLK	BRDY		1,477	1,477	11
7/8	SMLK	M345		24	24	12
7/8	WALLAWALLA	BORA		41,306	41,306	13
7/8	WALLAWALLA	BORA		16	16	14
7/8	WALLAWALLA	BRDY		16,057	16,057	15
7/8	WALLAWALLA	BRDY		9,962	9,962	16
7/8	WALLAWALLA	M345		21,813	21,813	17
7/8	WALLAWALLA	M345		3,073	3,073	18
7/8	BORA	M345		57	57	19
7/8	BRDY	M345		1,394	1,394	20
7/8	BRDY	M345		1,527	1,527	21
7/8	BRDY	LAGRANDE		864	864	22
7/8	LAGRANDE	BRDY		528	528	23
7/8	LAGRANDE	M345		249	249	24
7/8	M345	LAGRANDE		1,418	1,418	25
7/8	SMLK	BORA		1,722	1,722	26
7/8	SMLK	BRDY		50	50	27
7/8	BORA	BPAT.NWMT		2,006	2,006	28
7/8	BORA	LAGRANDE		3,377	3,377	29
7/8	BORA	LOLO		239	239	30
7/8	BPAT.NWMT	LAGRANDE		840	840	31
7/8	BPAT.NWMT	M345		50	50	32
7/8	BRDY	LAGRANDE		1,461	1,461	33
7/8	JBSN	BORA		1	1	34
			0	**7,243,160**	**7,243,160**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	Transalta Energy Marketing (U.S.) Inc.	Bonneville Power Administration	PacifiCorp East	NF
2	Transalta Energy Marketing (U.S.) Inc.	Bonneville Power Administration	Sierra Pacific Power	NF
3	Transalta Energy Marketing (U.S.) Inc.	Avista	PacifiCorp East	NF
4	Transalta Energy Marketing (U.S.) Inc.	Avista	Sierra Pacific Power	NF
5	Transalta Energy Marketing (U.S.) Inc.	Sierra Pacific Power	Bonneville Power Administration	NF
6	Transalta Energy Marketing (U.S.) Inc.	Sierra Pacific Power	Avista	NF
7	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp West	PacifiCorp East	NF
8	Transalta Energy Marketing (U.S.) Inc.	PacifiCorp West	Sierra Pacific Power	NF
9	Transalta Energy Marketing (U.S.) Inc.	Idaho Power Company	PacifiCorp East	NF
10	Transalta Energy Marketing (U.S.) Inc.	Idaho Power Company	Sierra Pacific Power	NF
11	Utah Associated Municipal Power Systems	PacifiCorp East	Sierra Pacific Power	NF
12	Utah Associated Municipal Power Systems	PacifiCorp East	Sierra Pacific Power	SFP
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
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	04/16/2019	End of 2018/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	BORA		7,536	7,536	1
7/8	LAGRANDE	M345		19,435	19,435	2
7/8	LOLO	BORA		378	378	3
7/8	LOLO	M345		30	30	4
7/8	M345	LAGRANDE		4,156	4,156	5
7/8	M345	LOLO		428	428	6
7/8	SMLK	BORA		15,623	15,623	7
7/8	SMLK	M345		100	100	8
7/8	WALLAWALLA	BORA		4,813	4,813	9
7/8	WALLAWALLA	M345		1,458	1,458	10
7/8	BORA	M345		2,039	2,039	11
7/8	BRDY	M345		844	844	12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			0	**7,243,160**	**7,243,160**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/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.
1,861,122	110,174		1,971,296	1
1,700,511	127,383		1,827,894	2
7,092,195	450,580		7,542,775	3
	12,936		12,936	4
	113,393		113,393	5
10,953	883		11,836	6
	54,759		54,759	7
	3,639		3,639	8
	12,229		12,229	9
				10
	4,928,159		4,928,159	11
	4,214,425		4,214,425	12
	8,190,939		8,190,939	13
	3,432,717		3,432,717	14
	3,398,730		3,398,730	15
	3,398,730		3,398,730	16
				17
	1,720		1,720	18
	761		761	19
	2,701		2,701	20
	6,965		6,965	21
	19,190		19,190	22
	1,421		1,421	23
	92		92	24
	938		938	25
	22,680		22,680	26
	1,215		1,215	27
	5,190		5,190	28
	3,226		3,226	29
	86		86	30
	874		874	31
	187		187	32
	856		856	33
	799		799	34
10,664,781	**40,664,251**	**0**	**51,329,032**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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.
	31		31	1
	3,282		3,282	2
	47		47	3
	4,557		4,557	4
	28		28	5
	84		84	6
	12		12	7
	796		796	8
	2,608		2,608	9
	9		9	10
	608		608	11
	118		118	12
	2		2	13
	56		56	14
	69		69	15
	37,345		37,345	16
	90		90	17
	44,925		44,925	18
	171,831		171,831	19
	10,341		10,341	20
	5,102		5,102	21
	8,101		8,101	22
	319		319	23
	253		253	24
	126,065		126,065	25
	8		8	26
	1,378		1,378	27
	24,237		24,237	28
	2,564		2,564	29
	51,349		51,349	30
	1,917		1,917	31
	323		323	32
	2,995		2,995	33
	6,338		6,338	34
10,664,781	**40,664,251**	**0**	**51,329,032**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	3,103		3,103	1
	105,674		105,674	2
	112,049		112,049	3
	136		136	4
	2,234		2,234	5
	13,737		13,737	6
	9,345		9,345	7
	26,671		26,671	8
	1,209		1,209	9
	1,741		1,741	10
	160		160	11
	95,630		95,630	12
	60		60	13
	3,338		3,338	14
	11,086		11,086	15
	27,765		27,765	16
	215,403		215,403	17
	151		151	18
	22,260		22,260	19
	13,553		13,553	20
	822		822	21
	41,914		41,914	22
	251		251	23
	104,019		104,019	24
	259,230		259,230	25
	42		42	26
	60		60	27
	36,257		36,257	28
	15,760		15,760	29
	30		30	30
	1,853		1,853	31
	132,087		132,087	32
	6,814		6,814	33
	4,432		4,432	34
10,664,781	**40,664,251**	**0**	**51,329,032**	

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.
	973		973	1
	163,017		163,017	2
	4,245		4,245	3
	955		955	4
	39,096		39,096	5
	32,345		32,345	6
	10,336		10,336	7
	333,190		333,190	8
	272		272	9
	101,879		101,879	10
	16,443		16,443	11
	853		853	12
	855,695		855,695	13
	463,275		463,275	14
	1,654		1,654	15
	5,502		5,502	16
	94,847		94,847	17
	3,746		3,746	18
	7,316		7,316	19
	1,512		1,512	20
	12,679		12,679	21
	914,176		914,176	22
	24		24	23
	732		732	24
	9,529		9,529	25
	8,970		8,970	26
	102,109		102,109	27
	31,236		31,236	28
	39		39	29
	752,269		752,269	30
	6,893		6,893	31
	5,986		5,986	32
	471,818		471,818	33
	70		70	34
10,664,781	**40,664,251**	**0**	**51,329,032**	

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/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.
	713		713	1
	8,881		8,881	2
	14,628		14,628	3
	6,095		6,095	4
	816		816	5
	589		589	6
	20		20	7
	743		743	8
	1,264,489		1,264,489	9
	3,862		3,862	10
	327		327	11
	23,506		23,506	12
	753		753	13
	22,011		22,011	14
	9,352		9,352	15
	2,995		2,995	16
	23,526		23,526	17
	5		5	18
	17,991		17,991	19
	16,882		16,882	20
	243		243	21
	2,540		2,540	22
	1,856		1,856	23
	2,149		2,149	24
	4,876		4,876	25
	3,069		3,069	26
	12,080		12,080	27
	14,099		14,099	28
	2,426		2,426	29
	64		64	30
	373,461		373,461	31
	886		886	32
	206,749		206,749	33
	26		26	34
10,664,781	**40,664,251**	**0**	**51,329,032**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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.
	5,266		5,266	1
	559		559	2
	1,140		1,140	3
	75,315		75,315	4
	201		201	5
	6,015		6,015	6
	3,421		3,421	7
	391		391	8
	1,118		1,118	9
	470		470	10
	369		369	11
	1,610		1,610	12
	224		224	13
	671		671	14
	28,925		28,925	15
	13,294		13,294	16
	403		403	17
	347		347	18
	45		45	19
	2,057		2,057	20
	2,818		2,818	21
	89		89	22
	103,054		103,054	23
	25,246		25,246	24
	18,929		18,929	25
	1,521		1,521	26
	503		503	27
	1,364		1,364	28
	123		123	29
	9,817		9,817	30
	1,364		1,364	31
	26,387		26,387	32
	3,667		3,667	33
	28,847		28,847	34
10,664,781	**40,664,251**	**0**	**51,329,032**	

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
	4,059		4,059	1
	20,383		20,383	2
	2,541		2,541	3
	1,919		1,919	4
	36,790		36,790	5
	2,615		2,615	6
	119,603		119,603	7
	16,475		16,475	8
	10,323		10,323	9
	29,210		29,210	10
	7,087		7,087	11
	2,030		2,030	12
	2,861		2,861	13
	17,853		17,853	14
	290		290	15
	24,559		24,559	16
	2,337		2,337	17
	2,575		2,575	18
	618		618	19
	644		644	20
	695		695	21
	5,395		5,395	22
	876		876	23
	26,832		26,832	24
	2,852		2,852	25
	40,801		40,801	26
	140,165		140,165	27
	4,101		4,101	28
	11,253		11,253	29
	161		161	30
	2,575		2,575	31
	157,154		157,154	32
	54,706		54,706	33
	4,107		4,107	34
10,664,781	**40,664,251**	**0**	**51,329,032**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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.
	5,871		5,871	1
	532,117		532,117	2
	10,216		10,216	3
	40,312		40,312	4
	685,749		685,749	5
	408,522		408,522	6
	2,401		2,401	7
	1,487		1,487	8
	25,873		25,873	9
	438		438	10
	9,508		9,508	11
	155		155	12
	265,910		265,910	13
	103		103	14
	103,368		103,368	15
	64,131		64,131	16
	140,423		140,423	17
	19,783		19,783	18
	252		252	19
	6,173		6,173	20
	6,762		6,762	21
	4,996		4,996	22
	3,053		3,053	23
	1,440		1,440	24
	8,199		8,199	25
	9,957		9,957	26
	289		289	27
	12,120		12,120	28
	20,404		20,404	29
	1,444		1,444	30
	5,075		5,075	31
	302		302	32
	8,827		8,827	33
	6		6	34
10,664,781	**40,664,251**	**0**	**51,329,032**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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.
	45,532		45,532	1
	117,425		117,425	2
	2,284		2,284	3
	181		181	4
	25,110		25,110	5
	2,586		2,586	6
	94,393		94,393	7
	604		604	8
	29,080		29,080	9
	8,809		8,809	10
	13,395		13,395	11
	5,541		5,541	12
				13
				14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
10,664,781	**40,664,251**	**0**	**51,329,032**	

Schedule Page: 328 Line No.: 1 Column: a
The network service agreement between Idaho Power and the Bonneville Power Administration for the Oregon Trail Electric Cooperative expires September 30, 2028.

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 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: a
The network service agreement between Idaho Power and the Bonneville Power Administration for the USBR expires December 31, 2023.

Schedule Page: 328 Line No.: 3 Column: a
The network service agreement between Idaho Power and the Bonneville Power Administration for the Priority Firm Customers expires September 30, 2028.

Schedule Page: 328 Line No.: 4 Column: a
The contract between Idaho Power and the Milner Irrigation District expires December 31, 2022.

Schedule Page: 328 Line No.: 4 Column: e
Legacy, contract prior to the Open Access Transmission Tariff

Schedule Page: 328 Line No.: 5 Column: a
The agreement between Idaho Power and the City of Seattle expires December 31, 2019. City of Seattle has re-sold this transmission service request to Morgan Stanley and Morgan Stanley is now responsible for payment.

Schedule Page: 328 Line No.: 5 Column: e
4, Open Access Transmission Tariff, Schedule 4 Energy Imbalance Service

Schedule Page: 328 Line No.: 6 Column: a
The contract between Idaho Power and PacifiCorp - Imnaha expires on March 31, 2021.

Schedule Page: 328 Line No.: 7 Column: a
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.: 8 Column: a
The agreement between Idaho Power and Cycle Horseshoe Bend Wind, LLC has no expiration date and can be terminated by either party at any time.

Schedule Page: 328 Line No.: 8 Column: e
5/6, Open Access Transmission Tariff, Schedule 5/6 Operating Reserves

Schedule Page: 328 Line No.: 11 Column: e
7/8, Open Access Transmission Tariff, Schedule 7/8 Firm/Non-Firm Point-to-Point Transmission Service

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Avista Corp-WWP Div	NF	10,275	10,275		84,472		84,472
2	Avista Corp-WWP Div	SFP	191,760	191,760		681,357		681,357
3	Bonneville Power Admin	LFP	215,473	215,473		1,134,792		1,134,792
4	Bonneville Power Admin	SFP	6,981	6,981		33,312		33,312
5	Bonneville Power Admin	NF	342	342		1,447		1,447
6	Bonneville Power Admin	OS					6,234	6,234
7	Bonneville Power Admin	OS					239,481	239,481
8	Bonneville Power Admin	OS	77,464	77,464				
9	Bonneville Power Admin	OS	30,836	30,836				
10	Bonneville Power Admin	OS	6,219	6,219				
11	Bonneville Power Admin	OS	10,615	10,615				
12	Bonneville Power Admin	OS					2,500	2,500
13	NorthWestern Energy	SFP	18	18		3,117		3,117
14	NorthWestern Energy	NF	1,229	1,229		7,837		7,837
15	NorthWestern Energy	OS					566	566
16	PacifiCorp Inc.	LFP	1,531	1,531		1,045,190		1,045,190
	TOTAL		555,222	555,222		3,251,876	350,279	3,602,155

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	PacifiCorp Inc.	SFP				3,517		3,517
2	PacifiCorp Inc.	NF	2,479	2,479		24,814		24,814
3	PacifiCorp Inc.	OS					44,060	44,060
4	PacifiCorp Inc.	OS					-5,348	-5,348
5	PacifiCorp Inc.	AD					-38,764	-38,764
6	PacifiCorp Inc.	AD					6,263	6,263
7	PacifiCorp Inc.	AD					-1,036	-1,036
8	PacifiCorp Inc.	AD					2,049	2,049
9	PacifiCorp Inc.	AD					94,530	94,530
10	PacifiCorp Inc.	AD					-256	-256
11	Puget Sound Energy, Inc	SFP				60,682		60,682
12	Seattle CIty Light	SFP				8,640		8,640
13	Snohomish County PUD	SFP				134,941		134,941
14	Tacoma Power	SFP				27,758		27,758
15								
16								
	TOTAL		555,222	555,222		3,251,876	350,279	3,602,155

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Schedule Page: 332 Line No.: 3 Column: b
Contract Expiration Date 12/31/2021
Schedule Page: 332 Line No.: 6 Column: b
Spinning/supplemental reserves
Schedule Page: 332 Line No.: 7 Column: b
Ancillary Services
Schedule Page: 332 Line No.: 8 Column: b
BPAT is provider for capacity reassignment settled with Snohomish County PUD.
Schedule Page: 332 Line No.: 9 Column: b
BPAT is provider for capacity reassignment settled with Puget Sound Energy.
Schedule Page: 332 Line No.: 10 Column: b
BPAT is provider for capacity reassignment settled with Seattle City Light.
Schedule Page: 332 Line No.: 11 Column: b
BPAT is provider for capacity reassignment settled with Tacoma Power.
Schedule Page: 332 Line No.: 12 Column: b
Processing Fee for Transmission Service
Schedule Page: 332 Line No.: 15 Column: b
Ancillary Services
Schedule Page: 332 Line No.: 16 Column: b
Contract Expiration Date 05/31/2019
Schedule Page: 332.1 Line No.: 3 Column: b
Ancillary Services
Schedule Page: 332.1 Line No.: 4 Column: b
April 2018 Intertie Adj
Schedule Page: 332.1 Line No.: 5 Column: b
2012-2016 FERC True-Up
Schedule Page: 332.1 Line No.: 6 Column: b
2014 PTP True-Up
Schedule Page: 332.1 Line No.: 7 Column: b
2015 PTP True-Up
Schedule Page: 332.1 Line No.: 8 Column: b
2016 PTP True-Up
Schedule Page: 332.1 Line No.: 9 Column: b
2017 PTP True-Up
Schedule Page: 332.1 Line No.: 10 Column: b
2017 FERC Refund
Schedule Page: 332.1 Line No.: 11 Column: b
BPAT is provider for capacity reassignment settled with Puget Sound Energy
Schedule Page: 332.1 Line No.: 12 Column: b
BPAT is provider for capacity reassignment settled with Seattle City Light
Schedule Page: 332.1 Line No.: 13 Column: b
BPAT is provider for capacity reassignment settled with Snohomish County PUD
Schedule Page: 332.1 Line No.: 14 Column: b
BPAT is provider for capacity reassignment settled with Tacoma Power

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	543,835
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	1,702,311
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	74,325
6		
7	Director Fees and Expenses	
8	Thomas Carlile	84,150
9	Richard Dahl	103,455
10	Annette Elg	86,130
11	Ronald Jibson	80,190
12	Judith Johansen	86,130
13	Dennis Johnson	82,170
14	Lamont Keen	30,938
15	Christine King	93,060
16	Richard Navarro	86,130
17	Robert Tintsman	187,110
18	Director travel and lodging	18,735
19		
20	Corporate Memberships and Subscriptions	
21	Arizona State University	50,000
22	Associated Taxpayers of Idaho	22,000
23	Bannock Development Corp	8,500
24	CEATI International, Inc.	15,250
25	ESource	31,624
26	Idaho Association of Commerce and Industry	15,500
27	National Association of Directors	8,075
28	National Hydropower Association	38,201
29	North American Energy Standard	7,000
30	Pacific NW Utilities	52,093
31	Southern Idaho Economic Developement	5,000
32	Sun Valley Economic Developement	5,500
33	Misc. Memberships under $5,000	41,700
34		
35	Chamber of Commerce and Other Civic Organizations	46,041
36		
37		
38		
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40		
41		
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43		
44		
45		
46	TOTAL	3,605,153

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

Recipient	Purpose	Amount
American Stock Transfer & Trust	Mgmt Services	$ 71,602
Bloomberg Finance LP	Misc Expense	24,506
Broadridge Financial Solutions	Misc Expense	49,767
Deutsche Bank	Broker Fees	30,000
EQ Shareholder Services	Mgmt Services	87,671
NASDAQ Corp Solutions	Mgmt Services	52,947
New York Stock Exchange	Listing Services	64,025
OKAPI Partners, LLC	Mgmt Services	19,800
Payroll Related Expenses	Misc Expense	177,463
PR Newswire	Misc Expense	17,288
Rivel Research Group	Mgmt Services	15,840
Stock Based Compensation	Misc Expense	1,039,102
Union Bank, N.A.	Misc Expense	9,680
Travel Expense-Stock Related	Misc Expense	15,868
Wells Fargo Shareowner Services	Mgmt Services	26,752
		$ 1,702,311

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

Recipient	Purpose	Amount
Bank of New York	Revenue Bonds	$ 7,450
Investis, Inc.	Website Design	7,325
Retirement Related Expense	Misc Expense	10,000
Port of Morrow, Poll Contr	Misc Expense	5,475
Miscellaneous Under $5000	Misc Expense	44,075
		$ 74,325

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

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

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

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			6,981,078		6,981,078
2	Steam Production Plant	47,229,753	566,665			47,796,418
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional	16,289,503				16,289,503
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant	16,055,212				16,055,212
7	Transmission Plant	22,288,563				22,288,563
8	Distribution Plant	39,058,129				39,058,129
9	Regional Transmission and Market Operation					
10	General Plant	15,411,427				15,411,427
11	Common Plant-Electric					
12	TOTAL	156,332,587	566,665	6,981,078		163,880,330

B. Basis for Amortization Charges

Acct 404	Balance 1/1/2018	2018 Amortization	Balance 12/31/2018	Remaining Months
(1)	0	12,000	48,000	48
(2)	8,736,987	522,009	8,214,978	-
(3)	4,684,179	189,691	4,494,488	284
(4)	12,134,210	5,849,562	17,327,222	-
(5)	2,884,300	287,899	2,596,400	108
(6)	169,657	56,544	113,113	24
(7)	1,797,458	63,373	4,488,479	-
Total	30,406,791	6,981,078	37,282,680	

(1) Shoshone-Bannock Tribe License & Use Agreement. (New five year advance payment starting January 2018, with a December 31, 2022 termination date.)
(2) Middle Snake Relicensing Costs (Amortized over a 30 year license period; licenses expire 07/31/34 and 02/28/35).
(3) Swan Falls Relicensing Costs (Amortized over a 30 year license period, license expires August 31, 2042).
(4) Computer Software packages (Amortized over a 62 month period).
(5) Shoshone-Bannock Right of Way (Termination date 12/31/27).
(6) Boardman Retrofit Tech Analysis (Scheduled decommission date 12/31/20).
(7) FERC License Compliance Costs (Termination date will be expiration date of the applicable FERC Licenses) .

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	310.20	649	75.00		4.48	R4.0	17.90
13	311.00	156,069	100.00	-9.00	3.17	S0.5	17.90
14	312.10	193,633	70.00	-5.00	3.47	S1.0	18.10
15	312.20	565,862	53.00	-8.00	4.15	R1.5	17.00
16	312.30	4,341	35.00	10.00	6.10	R3.0	13.50
17	314.00	172,390	45.00	-7.00	4.94	S0.5	16.50
18	315.00	74,658	60.00	-3.00	3.15	S1.5	16.80
19	316.00	14,908	35.00	2.00	7.53	S0.0	14.60
20	316.10	401	13.00	15.00	7.43	L2.0	5.40
21	316.40	250	13.00	15.00	1.24	L2.0	
22	316.50	1,363	13.00	15.00	4.98	L2.0	11.80
23	316.60	45			3.90		
24	316.70	268	21.00	15.00	0.33	S1.0	12.20
25	316.80	4,782	20.00	25.00	4.77	O1.0	17.80
26	316.90	14	35.00	15.00	2.43	S1.0	30.60
27	317.00	14,157					
28	Subtotal Steam	1,203,790					
29	331.00	199,926	120.00	-25.00	2.08	R2.5	35.80
30	332.10	19,461	120.00	-20.00	0.98	S1.5	46.20
31	332.20	250,254	120.00	-20.00	1.80	S1.5	31.20
32	332.30	5,472			1.15	Square	55.10
33	333.00	291,047	100.00	-10.00	1.92	R2.5	30.60
34	334.00	63,782	65.00	-10.00	2.82	R1.5	27.80
35	335.00	26,077	90.00	-5.00	2.18	R2.0	31.20
36	335.10	140	15.00		7.92	Square	7.90
37	335.20	42	20.00		0.80	Square	9.20
38	335.30	359	5.00		14.42	Square	2.50
39	336.00	11,882	100.00		2.58	R3.0	22.70
40	Subtotal Hydro	868,442					
41	341.00	143,339			2.72	Square	32.80
42	342.00	10,715	50.00		2.81	S2.5	28.70
43	343.00	227,444	40.00		3.18	R2.0	26.00
44	344.00	66,619	50.00		2.45	S2.0	28.40
45	344.10	95	25.00		4.00		
46	345.00	91,837	55.00		2.91	R2.0	29.30
47	346.00	6,491	35.00		3.24	R2.5	24.00
48	Subtotal Other	546,540					
49	350.20	34,297	100.00		0.89	R4.0	85.20
50	350.22	198	30.00		3.33		

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	352.00	81,024	65.00	-33.00	1.88	R3.0	53.20
13	353.00	441,026	52.00	-10.00	1.97	S0.5	42.00
14	354.00	211,358	80.00	-10.00	1.07	R4.0	71.10
15	355.00	193,820	65.00	-80.00	2.64	R1.5	53.90
16	355.10	1,388	10.00		10.00		
17	356.00	233,163	74.00	-50.00	1.87	R1.5	62.30
18	359.00	390	65.00		0.91	R2.5	33.30
19	Subtotal Transmission	1,196,664					
20	360.22	874	30.00		3.35		
21	361.00	40,284	70.00	-50.00	2.17	R3.0	54.40
22	362.00	254,363	55.00	-6.00	1.85	R1.5	42.90
23	364.00	266,497	58.00	-50.00	2.17	R1.5	44.10
24	364.10	5,199	12.00		8.34		
25	365.00	140,485	49.00	-30.00	2.65	R1.0	34.40
26	366.00	52,238	65.00	-25.00	1.89	R2.5	49.10
27	367.00	275,969	50.00	-11.00	1.90	R1.5	39.40
28	368.00	587,592	42.00	-7.00	2.17	R0.5	34.80
29	369.00	61,920	55.00	-40.00	1.58	R1.5	43.40
30	370.00	17,034	30.00	-5.00	2.05	O1.0	25.70
31	370.10	76,293	18.00	-5.00	5.39	R1.5	14.00
32	371.20	3,124	21.00	-5.00	2.88	R1.0	14.70
33	373.20	4,589	40.00	-30.00	1.73	R1.0	29.00
34	374.00	143					
35	Subtotal Distribution	1,786,604					
36	390.11	32,377	90.00	-3.00	2.08	S1.0	33.20
37	390.12	95,142	55.00	-3.00	2.11	R2.0	38.80
38	391.10	14,761	20.00		4.00	Square	12.30
39	391.20	26,565	5.00		20.00	Square	2.70
40	391.21	7,181	8.00		12.50	Square	3.50
41	392.10	872	13.00	15.00	7.07	L2.0	9.30
42	392.30	4,563	15.00	40.00	4.13	S2.5	9.70
43	392.40	25,932	13.00	15.00	6.20	L2.0	8.50
44	392.50	1,520	13.00	15.00	6.34	L2.0	8.90
45	392.60	44,915	21.00	15.00	3.95	S1.0	14.00
46	392.70	9,158	21.00	15.00	4.16	S1.0	12.30
47	392.90	5,905	35.00	15.00	2.24	S1.0	24.30
48	393.00	3,023	25.00		4.00	Square	17.40
49	394.00	11,095	20.00		5.00	Square	12.40
50	395.00	13,703	20.00		5.00	Square	10.60

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	396.00	19,234	20.00	25.00	2.97	O1.0	16.70
13	397.10	2,796	15.00		6.67	Square	4.70
14	397.20	25,443	15.00		6.67	Square	8.10
15	397.30	4,020	15.00		6.67	Square	9.70
16	397.40	19,671	15.00		6.02	Square	13.10
17	398.00	7,377	15.00		6.67	Square	8.60
18	Subtotal General	375,253					
19	Total Plant	5,977,293					
20							
21							
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Schedule Page: 336   Line No.: 28   Column: a

(Column: c,d,f, g) Plant accounts 31020 through 31650 and 31670 through 31690 are presented for Jim Bridger facility only. This data is provided by the most recent depreciation study; Jim Bridger was the only thermal production facility included in the depreciation study. Plant account 31660 is associated with Valmy facility only. Valmy was not part of the 2016 depreciation study, as Valmy has been reviewed for decommissioning within regulatory order #33771. There is no data for estimated service life, net salvage percentage, or mortality curve.

(Column: e) An average plant balance was used in computing these rates by plant account.

Schedule Page: 336   Line No.: 45   Column: a

Plant account 34410 (created in 2018) was not in the last depreciation study and has not been subject to depreciation study review.

Schedule Page: 336.2   Line No.: 19   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. Effective April 1, 1993 all depreciable plant is being depreciated using the straight-line remaining life method.

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/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	4,033,717		4,033,717	
3					
4	General Regulatory Expenses and				
5	Various other Dockets		33,170	33,170	
6					
7	Oregon Hydro - Fees Amortization	158,501		158,501	
8					
9	Regulatory Commission Expenses - Idaho				
10	Rate Case - Misc expenses		81,752	81,752	47,835
11					
12	Regulatory Commission Expenses - Oregon				
13	Rate Case - Misc expenses		147,671	147,671	
14	General Regulatory		528,500	528,500	
15	Other OPUC expenses		38,047	38,047	
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL	4,192,218	829,140	5,021,358	47,835

REGULATORY COMMISSION EXPENSES (Continued)

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

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
							1
Electric	928	4,033,717					2
							3
							4
Electric	928	33,170					5
							6
Electric	928	158,501					7
							8
							9
Electric	928	-606	62,242	928203	82,358	27,719	10
							11
							12
Electric	928	147,671					13
Electric	928	528,500					14
Electric	928	38,047					15
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		4,939,000	62,242		82,358	27,719	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	04/16/2019	End of 2018/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 2018.	
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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	04/16/2019	End of 2018/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 Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/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	21,306,744		
4	Transmission	6,914,725		
5	Regional Market			
6	Distribution	17,654,144		
7	Customer Accounts	9,224,652		
8	Customer Service and Informational	4,581,573		
9	Sales			
10	Administrative and General	78,819,317		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	138,501,155		
12	Maintenance			
13	Production	4,032,892		
14	Transmission	2,789,119		
15	Regional Market			
16	Distribution	7,667,503		
17	Administrative and General	1,066,068		
18	TOTAL Maintenance (Total of lines 13 thru 17)	15,555,582		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	25,339,636		
21	Transmission (Enter Total of lines 4 and 14)	9,703,844		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	25,321,647		
24	Customer Accounts (Transcribe from line 7)	9,224,652		
25	Customer Service and Informational (Transcribe from line 8)	4,581,573		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	79,885,385		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	154,056,737		154,056,737
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	04/16/2019	End of 2018/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)	154,056,737		154,056,737
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	Store Expense	4,787,013		4,787,013
79	Other Clearing Accounts	3,551,789		3,551,789
80	Construction Work in Progress	60,474,567		60,474,567
81	Other Work in Progress	3,788,499		3,788,499
82	Other Accounts	5,131,177		5,131,177
83	Indirect Loading		47,057,467	47,057,467
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	77,733,045	47,057,467	124,790,512
96	TOTAL SALARIES AND WAGES	231,789,782	47,057,467	278,847,249

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Schedule Page: 354 Line No.: 83 Column: a

Amount reported is total amount of indirect loading. The loading is allocated to departments based on labor charges.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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			265,665			
2	Reactive Supply and Voltage			18,441			
3	Regulation and Frequency Response				3,043,661	KW	298,127
4	Energy Imbalance				703	KWH	14,011
5	Operating Reserve - Spinning			3,411	4,134,901	KW	405,014
6	Operating Reserve - Supplement			2,823	4,134,901	KW	405,014
7	Other						
8	Total (Lines 1 thru 7)			290,340	11,314,166		1,122,166

Schedule Page: 398 Line No.: 1 Column: b

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

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:

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	3,324	2	900	1,542	224	973		585	
2	February	3,104	25	2000	1,292	191	973		648	
3	March	3,172	7	800	1,445	212	973		542	
4	Total for Quarter 1				4,279	627	2,919		1,775	
5	April	2,915	23	800	993	211	973		738	
6	May	3,496	8	1700	2,001	294	973		228	
7	June	4,429	27	2000	2,793	378	973		285	
8	Total for Quarter 2				5,787	883	2,919		1,251	
9	July	4,594	25	1800	3,021	359	973		241	
10	August	4,642	9	1700	3,241	361	973		67	
11	September	3,854	6	2000	2,420	293	973		168	
12	Total for Quarter 3				8,682	1,013	2,919		476	
13	October	2,993	15	800	1,389	243	973		388	
14	November	3,135	15	800	1,397	209	973		556	
15	December	3,368	13	800	1,334	240	973		821	
16	Total for Quarter 4				4,120	692	2,919		1,765	
17	Total Year to Date/Year				22,868	3,215	11,676		5,267	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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)
1	SOURCES OF ENERGY	
2	Generation (Excluding Station Use):	
3	Steam	3,274,144
4	Nuclear	
5	Hydro-Conventional	8,681,811
6	Hydro-Pumped Storage	
7	Other	1,407,862
8	Less Energy for Pumping	
9	Net Generation (Enter Total of lines 3 through 8)	13,363,817
10	Purchases	5,389,494
11	Power Exchanges:	
12	Received	106,210
13	Delivered	145,139
14	Net Exchanges (Line 12 minus line 13)	-38,929
15	Transmission For Other (Wheeling)	
16	Received	7,243,160
17	Delivered	7,239,947
18	Net Transmission for Other (Line 16 minus line 17)	3,213
19	Transmission By Others Losses	
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	18,717,595

Line No.	Item (a)	MegaWatt Hours (b)
21	DISPOSITION OF ENERGY	
22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	14,586,522
23	Requirements Sales for Resale (See instruction 4, page 311.)	
24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	2,863,637
25	Energy Furnished Without Charge	
26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
27	Total Energy Losses	1,267,436
28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	18,717,595

Schedule Page: 401 Line No.: 18 Column: b

Page 329 Column I differs from page 401 by 3,213 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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	1,670,126	403,276	2,145	4	0900
30	February	1,399,249	268,337	2,226	20	0800
31	March	1,551,731	412,857	1,989	6	0800
32	April	1,600,079	506,996	1,979	27	1800
33	May	1,549,946	256,468	2,367	29	2000
34	June	1,667,528	130,332	3,138	25	1900
35	July	1,942,099	77,882	3,392	9	1900
36	August	1,737,707	69,934	3,381	10	1800
37	September	1,417,711	171,251	2,704	6	1800
38	October	1,239,754	152,788	1,806	15	0900
39	November	1,381,789	206,771	2,025	13	0800
40	December	1,559,876	206,745	2,267	6	0800
41	TOTAL	18,717,595	2,863,637			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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)	702			60		
7	Plant Hours Connected to Load	8764			3208		
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	2511814000			151517000		
13	Cost of Plant: Land and Land Rights	509671			106610		
14	Structures and Improvements	71591785			12626048		
15	Equipment Costs	637997616			64057418		
16	Asset Retirement Costs	9164040			5046008		
17	Total Cost	719263112			81836084		
18	Cost per KW of Installed Capacity (line 17/5) Including	933.5018			1274.7054		
19	Production Expenses: Oper, Supv, & Engr	174038			455021		
20	Fuel	87601038			4049522		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	5691535			707167		
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	6791168			665880		
27	Rents	250861			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	100602			112653		
30	Maintenance of Structures	0			50779		
31	Maintenance of Boiler (or reactor) Plant	7148511			115654		
32	Maintenance of Electric Plant	2613274			1329883		
33	Maintenance of Misc Steam (or Nuclear) Plant	6963587			66027		
34	Total Production Expenses	117334614			7552586		
35	Expenses per Net KWh	0.0467			0.0498		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil		Coal	Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrel		Tons	Barrels	
38	Quantity (Units) of Fuel Burned	1423953	6257	0	89853	796	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	9276	140000	0	8650	138800	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	57.743	105.197	0.000	42.009	99.690	0.000
41	Average Cost of Fuel per Unit Burned	61.035	76.113	0.000	44.057	90.385	0.000
42	Average Cost of Fuel Burned per Million BTU	3.290	12.944	0.000	2.548	15.501	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.035	0.000	0.000	0.027	0.000	0.000
44	Average BTU per KWh Net Generation	10531.000	0.000	0.000	10284.000	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	04/16/2019	End of 2018/Q4

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

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

Plant Name: *Valmy* (d)			Plant Name: *Danskin* (e)			Plant Name: *Bennett Mountain* (f)			Line No.
Steam			Gas Turbine			Gas Turbine			1
Outdoor			Conventional			Conventional			2
1981			2001			2005			3
1985			2008			2005			4
283.50			270.90			172.80			5
260			243			178			6
3765			810			1121			7
0			261			164			8
0			0			0			9
0			0			0			10
0			6			5			11
610813000			127648000			149158000			12
1106140			402745			0			13
71851394			6054979			1790867			14
330860448			111156785			53984084			15
-53303			0			0			16
403764679			117614509			55774951			17
1424.2140			434.1621			322.7717			18
575883			151705			4419			19
23873411			1993109			2928044			20
0			0			0			21
3514032			0			0			22
0			0			0			23
0			0			0			24
1868433			586841			423794			25
1677245			279674			176068			26
0			0			0			27
0			0			0			28
0			0			0			29
298643			82374			84059			30
3583035			5854			4690			31
601869			1938409			166912			32
113089			0			0			33
36105640			5037966			3787986			34
0.0591			0.0395			0.0254			35
Coal	Oil		Gas			Gas			36
Tons	Barrels		MCF			MCF			37
325634	8080	0	1322215	0	0	1656255	0	0	38
9330	138778	0	1027	0	0	1027	0	0	39
43.968	107.119	0.000	1.507	0.000	0.000	1.768	0.000	0.000	40
69.421	104.649	0.000	1.507	0.000	0.000	1.768	0.000	0.000	41
3.804	17.954	0.000	3.350	0.000	0.000	3.580	0.000	0.000	42
0.039	0.000	0.000	0.016	0.000	0.000	0.020	0.000	0.000	43
9806.000	0.000	0.000	10638.000	0.000	0.000	11404.000	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	04/16/2019	End of 2018/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)	298			0		
7	Plant Hours Connected to Load	4287			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	24			0		
12	Net Generation, Exclusive of Plant Use - KWh	1131020000			0		
13	Cost of Plant: Land and Land Rights	2287261			0		
14	Structures and Improvements	135480987			0		
15	Equipment Costs	237068055			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	374836303			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	1177.0649			0		
19	Production Expenses: Oper, Supv, & Engr	489767			0		
20	Fuel	12744946			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	3502791			0		
26	Misc Steam (or Nuclear) Power Expenses	824953			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	48859			0		
31	Maintenance of Boiler (or reactor) Plant	55349			0		
32	Maintenance of Electric Plant	535684			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	18202349			0		
35	Expenses per Net KWh	0.0161			0.0000		
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	9423468	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	1.352	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	1.352	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	2.980	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.011	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	8557.000	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	04/16/2019	End of 2018/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)	107	53
7	Plant Hours Connect to Load	6,972	8,613
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	489,268,000	353,493,000
13	Cost of Plant		
14	Land and Land Rights	875,319	768,366
15	Structures and Improvements	11,970,406	1,757,779
16	Reservoirs, Dams, and Waterways	4,293,075	9,087,082
17	Equipment Costs	33,375,913	21,219,167
18	Roads, Railroads, and Bridges	839,276	486,477
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	51,353,989	33,318,871
21	Cost per KW of Installed Capacity (line 20 / 5)	556.3812	444.2516
22	Production Expenses		
23	Operation Supervision and Engineering	224,759	760,767
24	Water for Power	1,841,919	810,710
25	Hydraulic Expenses	182,132	918,291
26	Electric Expenses	60,215	65,676
27	Misc Hydraulic Power Generation Expenses	347,490	479,288
28	Rents	187	4,797
29	Maintenance Supervision and Engineering	6,016	4,482
30	Maintenance of Structures	108,471	34,773
31	Maintenance of Reservoirs, Dams, and Waterways	6,594	11,079
32	Maintenance of Electric Plant	185,333	80,324
33	Maintenance of Misc Hydraulic Plant	100,014	172,129
34	Total Production Expenses (total 23 thru 33)	3,063,130	3,342,316
35	Expenses per net KWh	0.0063	0.0095

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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
652.60	12.42	190.00	5
581	14	210	6
8,736	8,736	8,736	7
			8
747	15	221	9
220	1	202	10
8	2	6	11
2,418,886,000	46,879,000	1,090,414,000	12
			13
18,382,251	82,142	1,212,767	14
39,790,736	7,328,252	13,911,719	15
67,636,458	3,145,630	31,550,233	16
114,036,450	13,486,249	22,010,550	17
1,458,769	122,668	585,876	18
0	0	0	19
241,304,664	24,164,941	69,271,145	20
369.7589	1,945.6474	364.5850	21
			22
610,156	179,709	453,620	23
553,819	226,366	397,342	24
1,197,804	484,107	876,365	25
385,880	119,254	263,515	26
644,079	262,533	541,250	27
118,503	73	19,430	28
27,457	2,051	7,089	29
43,903	8,297	85,074	30
38,484	4	19,895	31
1,236,198	25,828	149,786	32
597,192	108,954	254,051	33
5,453,475	1,417,176	3,067,417	34
0.0023	0.0302	0.0028	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	04/16/2019	End of 2018/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)	435	22
7	Plant Hours Connect to Load	8,733	8,731
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	445	25
10	(b) Under the Most Adverse Oper Conditions	137	21
11	Average Number of Employees	5	1
12	Net Generation, Exclusive of Plant Use - Kwh	2,194,877,000	136,032,000
13	Cost of Plant		
14	Land and Land Rights	1,880,381	205,376
15	Structures and Improvements	2,992,730	3,954,760
16	Reservoirs, Dams, and Waterways	53,033,657	6,952,853
17	Equipment Costs	22,562,410	15,703,831
18	Roads, Railroads, and Bridges	922,781	1,507,442
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	81,391,959	28,324,262
21	Cost per KW of Installed Capacity (line 20 / 5)	207.8977	1,301.0685
22	Production Expenses		
23	Operation Supervision and Engineering	382,960	161,624
24	Water for Power	386,745	809,253
25	Hydraulic Expenses	839,422	232,895
26	Electric Expenses	224,884	39,427
27	Misc Hydraulic Power Generation Expenses	598,388	155,367
28	Rents	32,319	0
29	Maintenance Supervision and Engineering	8,884	2,647
30	Maintenance of Structures	4,186	4,469
31	Maintenance of Reservoirs, Dams, and Waterways	38,768	37,229
32	Maintenance of Electric Plant	136,214	47,158
33	Maintenance of Misc Hydraulic Plant	440,678	87,343
34	Total Production Expenses (total 23 thru 33)	3,093,448	1,577,412
35	Expenses per net KWh	0.0014	0.0116

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	27.17	52.90	5
92	23	51	6
8,736	8,435	7,852	7
			8
91	24	53	9
84	14	50	10
5	4	2	11
568,652,000	123,727,000	262,039,000	12
			13
5,725,987	292,113	255,499	14
9,944,637	27,522,981	11,184,280	15
11,419,128	15,989,465	8,968,780	16
14,557,460	32,113,032	22,346,634	17
1,602,868	835,946	1,917,603	18
0	0	0	19
43,250,080	76,753,537	44,672,796	20
522.3440	2,824.9370	844.4763	21
			22
784,431	424,066	431,353	23
870,409	485,862	302,895	24
1,169,627	598,892	214,798	25
84,862	76,877	71,378	26
649,984	427,720	237,963	27
51,684	8,028	3,572	28
6,377	7,472	2,860	29
115,940	54,669	50,087	30
48,851	26,264	1,367	31
149,713	284,662	89,630	32
109,902	131,714	49,267	33
4,041,780	2,526,226	1,455,170	34
0.0071	0.0204	0.0056	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	04/16/2019	End of 2018/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	11.50
6	Net Peak Demand on Plant-Megawatts (60 minutes)	35	13
7	Plant Hours Connect to Load	8,736	7,199
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	3
12	Net Generation, Exclusive of Plant Use - Kwh	245,042,000	82,751,000
13	Cost of Plant		
14	Land and Land Rights	202,399	313,328
15	Structures and Improvements	2,805,131	1,563,244
16	Reservoirs, Dams, and Waterways	7,290,730	9,868,914
17	Equipment Costs	9,020,362	4,843,239
18	Roads, Railroads, and Bridges	29,359	115,108
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	19,347,981	16,703,833
21	Cost per KW of Installed Capacity (line 20 / 5)	560.8110	1,452.5072
22	Production Expenses		
23	Operation Supervision and Engineering	156,937	291,313
24	Water for Power	196,614	305,661
25	Hydraulic Expenses	257,792	342,250
26	Electric Expenses	117,643	41,112
27	Misc Hydraulic Power Generation Expenses	181,359	290,334
28	Rents	0	203
29	Maintenance Supervision and Engineering	4,534	4,092
30	Maintenance of Structures	59,964	34,827
31	Maintenance of Reservoirs, Dams, and Waterways	22,230	3,809
32	Maintenance of Electric Plant	127,891	172,399
33	Maintenance of Misc Hydraulic Plant	91,677	61,315
34	Total Production Expenses (total 23 thru 33)	1,216,641	1,547,315
35	Expenses per net KWh	0.0050	0.0187

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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	62	60	6
0	8,729	7,104	7
			8
0	64	61	9
0	60	1	10
0	6	2	11
0	327,431,000	294,476,000	12
			13
114,368	424,428	138,100	14
50,401,118	3,561,030	10,663,927	15
13,556,785	7,754,799	17,767,002	16
2,499,974	17,750,696	29,294,641	17
142,581	88,693	501,877	18
0	0	0	19
66,714,826	29,579,646	58,365,547	20
0.0000	492.9941	981.7586	21
			22
0	442,923	262,033	23
0	390,644	1,471,384	24
7,337,458	468,480	176,309	25
0	182,453	61,225	26
128	369,552	311,777	27
0	4,110	3,798	28
0	4,533	3,444	29
0	81,289	18,683	30
0	13,884	51,433	31
0	123,040	80,199	32
231,546	83,459	78,910	33
7,569,132	2,164,367	2,519,195	34
0.0000	0.0066	0.0086	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	04/16/2019	End of 2018/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	2.9	17,281	3,565,864
3	Thousand Springs	1912	6.80	7.0	30,563	12,013,559
4						
5						
6	Internal Combustion:					
7	Salmon Diesel	1967	5.00	4.0	36	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	04/16/2019	End of 2018/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
1,426,346	168,784		64,735			2
1,766,700	252,307		158,640			3
						4
						5
						6
181,852				Diesel		7
						8
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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	04/16/2019	End of 2018/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	0.08		1
4	Hemingway	Midpoint	500.00	500.00	S Tower	0.15		1
5	Summer Lake	Hemingway	500.00	500.00	S Tower	53.08		1
6	Hemingway	Midpoint	500.00	500.00	S Tower	47.76		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	19.81		1
11	Jim Bridger	Populus	345.00	345.00	S Tower	60.91		1
12	Populus	Kinport	345.00	345.00	S Tower	7.42		1
13	Jim Bridger	Populus	345.00	345.00	S Tower	61.08		1
14	Populus	Borah	345.00	345.00	S Tower	9.05		1
15	Goshen	Kinport	345.00	345.00	S Tower	7.48		1
16	Midpoint	Borah #1	345.00	345.00	H Wood	51.07		1
17	Midpoint	Borah #2	345.00	345.00	H Wood	49.98		2
18	Adelaide Tap	Adelaide	345.00	345.00	H Wood	1.72		2
19								
20	Quartz	LaGrande	230.00	230.00	H Wood	45.97		1
21	Midpoint	Hunt	230.00	230.00	S Tower	0.70		2
22	Brady	Antelope	230.00	230.00	H Wood	56.38		1
23	Brady	Treasureton	230.00	230.00	H Wood	0.08		1
24	Brady #1 & #2	Kinport	230.00	230.00	S Tower	17.94		2
25	Brownlee	Ontario	230.00	230.00	S Tower	72.67		1
26	Mora	Bowmont	138.00	230.00	S P Wood	9.99		1
27	Mora	Bowmont	138.00	230.00	H Wood	8.75		1
28	Caldwell 710	Locust	230.00	230.00	SP Steel	18.50		1
29	Boise Bench	Caldwell	230.00	230.00	S Tower	7.69		1
30	Boise Bench	Caldwell	230.00	230.00	H Wood	33.49		1
31	Boise Bench	Cloverdale	230.00	230.00	S Tower	15.91		2
32	Boardman	Dalreed Sub	230.00	230.00	H Wood	1.67		1
33	Brownlee 714	Oxbow	230.00	230.00	SP Steel	11.04		2
34	Caldwell	Ontario	230.00	230.00	H Wood	30.06		1
35	Caldwell	Ontario	230.00	230.00	S Tower	3.14		1
36					TOTAL	4,754.64	11.02	205

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/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.
1272 ACSR	256,381	15,977,947	16,234,328					1
2X1780 ACSR		446,708	446,708					2
1272 ACSR								3
1272 ACSR								4
3X1272 ACSR		18,826,061	18,826,061					5
3X1272 ACSR		17,078,061	17,078,061					6
								7
1272 ACSR	483,309	5,330,790	5,814,099					8
795 ACSR	571,979	11,226,882	11,798,861					9
1272 ACSR	344,220	4,397,073	4,741,293					10
1272 ACSR		9,534,541	9,534,541					11
1272 ACSR								12
1272 ACSR		9,257,404	9,257,404					13
1272 ACSR								14
2X1272 ACSR		583,947	583,947					15
715.5 ACSR	283,143	12,832,864	13,116,007					16
715.5 ACSR	64,851	15,978,637	16,043,488					17
715.5 ACSR	51,448	224,249	275,697					18
								19
795 ACSR	62,218	7,078,093	7,140,311					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	1,144,918	1,163,747					24
2X954 ACSR	1,676,838	20,551,937	22,228,775					25
715.5 ACSR	413,793	2,377,905	2,791,698					26
715.5 ACSR								27
1590 ACSR	2,378,436	8,775,086	11,153,522					28
1272 ACSR	1,748,202	7,740,608	9,488,810					29
715.5 ACSR								30
1272 ACSR	3,062,812	6,582,985	9,645,797					31
795 AAC		89,089	89,089					32
954 ACSR	34,174	16,026,470	16,060,644					33
2X954 ACSR	236,152	9,384,090	9,620,242					34
1272 ACSR								35
	34,835,917	639,955,720	674,791,637	7,787,360	1,544,297	2,710,673	12,042,330	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	04/16/2019	End of 2018/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)	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)	On Structures of Another Line (g)	Number Of Circuits (h)
1	Bennett Mtn PP	Rattlesnake TS	230.00	230.00	SP Steel	4.43		1
2	Borah	Hunt	230.00	230.00	H Steel	68.12		1
3	Danskin	Hubbard	230.00	230.00	H Steel	36.25		1
4	Danskin	Hubbard	230.00	230.00	SP Steel	1.84		1
5	Danskin	Hubbard	230.00	230.00	SP Steel	1.30		2
6	Danskin	Bennett Mtn	230.00	230.00	SP Steel	5.39		1
7	Hemingway	Bowmont	230.00	230.00	SP Steel	12.94		1
8	Langley Gulch	Galloway Rd	138.00	230.00	SP Steel	14.19		1
9	Galloway Rd	Willis Tap	138.00	230.00	SP Steel	2.09		1
10	Walla Walla	Hurricane	230.00	230.00	H Wood	30.55		1
11	Boise Bench	Midpoint #1	230.00	230.00	S Tower	0.71		1
12	Boise Bench	Midpoint #1	230.00	230.00	H Wood	108.68		1
13	Brownlee	Quartz Jct	230.00	230.00	S Tower	1.51		1
14	Brownlee	Quartz Jct	230.00	230.00	H Wood	41.30		1
15	Brownlee	Boise Bench #1 & #2	230.00	230.00	S Tower	99.78		2
16	Oxbow	Brownlee	230.00	230.00	S Tower	10.35		2
17	Boise Bench	Midpoint #2	230.00	230.00	S Tower	3.49		1
18	Boise Bench	Midpoint #2	230.00	230.00	H Wood	102.17		1
19	Oxbow	Pallette Jct	230.00	230.00	S Tower	20.11		2
20	Pallette Jct	Imnaha	230.00	230.00	H Wood	24.43		2
21	Hells Canyon	Palette Jct	230.00	230.00	S Tower	9.05		2
22	Brownlee	Boise Bench	230.00	230.00	S Tower	102.11		2
23	Boise Bench	Midpoint #3	230.00	230.00	H Wood	106.29		1
24	Palette Jct	Enterprise	230.00	230.00	H Wood	29.60		1
25	Borah	Brady #2	230.00	230.00	S Tower	0.42		1
26	Borah	Brady #2	230.00	230.00	H Wood	3.52		1
27	Borah	Brady #1	230.00	230.00	H Wood	3.84		1
28								
29	Goshen	State Line	161.00	161.00	H Wood	40.89		1
30	Don	Goshen	161.00	161.00	S Tower	2.37		2
31	Don	Goshen	161.00	161.00	H Wood	48.42		2
32	Antelope	Goshen	161.00	161.00	H Wood	5.67		1
33	Goshen	State Line	161.00	161.00	H Wood	10.93		1
34	Goshen	State Line	161.00	161.00	H Wood	7.84		1
35								
36					TOTAL	4,754.64	11.02	205

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/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.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
(i)	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
1272 ACSR	81,701	1,666,354	1,748,055					1
1590 ACSR	624,917	22,467,321	23,092,238					2
1590 ACSR		15,210,561	15,210,561					3
1590 ACSR								4
1590 ACSR								5
1590 ACSR		3,528,033	3,528,033					6
1590 ACSR	1,854,996	9,277,980	11,132,976					7
1590 ACSR	948,166	9,067,609	10,015,775					8
1272 ACSR								9
1272 ACSR		6,471,944	6,471,944					10
715.5 ACSR	385,287	14,623,370	15,008,657					11
715.5 ACSR								12
795 ACSR	53,068	4,833,736	4,886,804					13
795 ACSR								14
VARIOUS	289,923	9,198,927	9,488,850					15
1272 ACSR	14,810	1,296,859	1,311,669					16
715.5 ACSR	227,814	17,830,886	18,058,700					17
VARIOUS								18
1272 ACSR	87,468	3,933,180	4,020,648					19
1272 ACSR	171,081	2,081,470	2,252,551					20
1272 ACSR	44,687	1,252,130	1,296,817					21
954 ACSR	184,805	6,411,734	6,596,539					22
715.5 ACSR	247,846	8,032,328	8,280,174					23
1272 ACSR	84,014	1,927,018	2,011,032					24
1272 ACSR	3,068	531,106	534,174					25
715.5 ACSR								26
1272 ACSR	7,248	421,273	428,521					27
								28
250 COPPER	375,576	2,879,058	3,254,634					29
715.5 ACSR	88,204	2,597,887	2,686,091					30
397.5 ACSR								31
397.5 ACSR		784,659	784,659					32
250 COPPER	116,873	1,322,937	1,439,810					33
250 COPPER	76,969	482,272	559,241					34
								35
	34,835,917	639,955,720	674,791,637	7,787,360	1,544,297	2,710,673	12,042,330	36

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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	American Falls Power Plant	Adelaide	138.00	138.00	H Wood	14.07		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	1.13		2
4	Nampa	Caldwell	138.00	138.00	S P Wood	9.59		2
5	Upper Salmon	Mountain Home Jct	138.00	138.00	H Wood	54.36		1
6	Upper Salmon	Cliff	138.00	138.00	H Wood	30.81		1
7	Eastgate	Russet	138.00	138.00	S P Wood	2.06		1
8	Brady	Fremont	138.00	138.00	S Tower	1.01		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	84.73		2
12	Emmett Jct	Payette	138.00	138.00	H Wood	66.46		2
13	Mountain Home AFB Tap		138.00	138.00	H Wood	6.20		1
14	Ontario	Quartz	138.00	138.00	H Wood	73.20		1
15	King	American Falls PP	138.00	138.00	S Tower	0.91		2
16	King	American Falls PP	138.00	138.00	H Wood	142.16		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	6.19		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	125.54		1
22	King	Wood River	138.00	138.00	H Wood	63.94		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	10.37		2
25	Quartz	John Day	138.00	138.00	H Wood	67.30		1
26	Sinker Creek Tap		138.00	138.00	H Wood	2.79		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	1.81		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	4,754.64	11.02	205

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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	423,656	450,163					1
250 COPPER								2
715.5 ACSR	21,327	249,232	270,559					3
795 AAC	1,731,589	4,845,110	6,576,699					4
795 ACSR	78,078	5,041,293	5,119,371					5
795 ACSR	43,568	2,995,670	3,039,238					6
795 AAC	270,823	561,561	832,384					7
VARIOUS	564,932	4,733,979	5,298,911					8
VARIOUS								9
VARIOUS								10
VARIOUS	76,823	3,725,128	3,801,951					11
VARIOUS	55,521	4,706,354	4,761,875					12
397.5 ACSR	5,086	81,843	86,929					13
VARIOUS	34,428	6,851,738	6,886,166					14
715.5 ACSR	216,919	10,955,640	11,172,559					15
715.5 ACSR								16
715.5 ACSR								17
4\0	4,191	467,909	472,100					18
954 ACSR		96,921	96,921					19
250 COPPER	2,741	753,925	756,666					20
VARIOUS	28,490	5,062,297	5,090,787					21
VARIOUS	186,198	24,499,074	24,685,272					22
397.5 ACSR								23
VARIOUS	225,602	1,646,308	1,871,910					24
397.5 ACSR	96,582	2,699,802	2,796,384					25
VARIOUS	11,083	133,347	144,430					26
715.5 ACSR	3,123,380	9,714,182	12,837,562					27
VARIOUS								28
795AAC								29
1272 ACSR								30
250 COPPER	450	187,848	188,298					31
397.5 ACSR	349,712	7,121,949	7,471,661					32
397.5 ACSR								33
397.5 ACSR	141,534	2,745,214	2,886,748					34
397.5 ACSR								35
	34,835,917	639,955,720	674,791,637	7,787,360	1,544,297	2,710,673	12,042,330	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	04/16/2019	End of 2018/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	Lowell Jct	Nampa	138.00	138.00	S P Wood	7.49		2
2	Hunt	Milner	138.00	138.00	S P Wood	19.42		1
3	Strike	Bruneau Bridge	138.00	138.00	H Wood	13.49		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	25.20		2
7	Twin Falls	Russett	138.00	138.00	S P Wood	1.71		1
8	Blackfoot	Aiken	46.00	138.00	S P Wood	6.22		2
9	Peterson	Tendoy	69.00	138.00	H Wood	57.02		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	13.11		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	6.75		1
18	Star	Lansing	138.00	138.00	S P Steel	5.50		1
19	Karcher Sub	Zilog Tap	138.00	138.00	S P Steel	3.49		1
20	Zilog	Can Ada	138.00	138.00	S P Steel	1.50		1
21	Cloverdale - 712	712 - Wye	138.00	138.00	S P Steel	0.42	4.02	1
22	Victory Jct	Victory	138.00	138.00	S P Steel	1.89		1
23	Butler	Wye	138.00	138.00	S P Steel	2.94		1
24	Horseflat	Starkey	138.00	138.00	H Wood	33.97		1
25	Starkey	Mccall	138.00	138.00	S P Steel	2.23		2
26	Starkey	Mccall	138.00	138.00	H Wood	3.80		1
27	Starkey	Mccall	138.00	138.00	S P Steel	1.50		1
28	Starkey	Mccall	138.00	138.00	S P Wood	17.61		1
29	Chestnut	Happy Valley	138.00	138.00	S P Steel	2.78		1
30	Garnet	Ward		138.00				
31	McCall	Lake Fork	138.00	138.00	S P Wood	8.89		1
32	McCall	Lake Fork	138.00	138.00	S Steel	2.90		
33	Caldwell	Willis	138.00	138.00	S P Steel	1.30		1
34	Caldwell	Willis	138.00	138.00	S P Steel	1.59		1
35	Caldwell	Willis	138.00	138.00	S P Wood	0.87		1
36					TOTAL	4,754.64	11.02	205

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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)	
715.5 ACSR	211,131	1,454,879	1,666,010					1
715.5 ACSR	3,324	1,470,273	1,473,597					2
397.5 ACSR	14,927	717,475	732,402					3
715.5 ACSR	13,734	1,072,294	1,086,028					4
397.5 ACSR	18,223	1,301,873	1,320,096					5
VARIOUS	66,286	3,219,499	3,285,785					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	3,504,326	3,900,022					9
715.5 ACSR	343,955	2,184,427	2,528,382					10
795 ACSR								11
715.5 ACSR	14,697	736,552	751,249					12
795 AAC		50,319	50,319					13
795 AAC	308,141	2,165,954	2,474,095					14
1272 ACSR	935,810	3,442,874	4,378,684					15
1272 ACSR	34,687	838,605	873,292					16
715.5 ACSR	179,817	6,681,791	6,861,608					17
795 AAC								18
795 AAC	43,911	434,341	478,252					19
795 AAC								20
1272 ACSR	140,412	2,577,075	2,717,487					21
1272 ACSR								22
795 ACSR	134,471	1,405,436	1,539,907					23
715.5 ACSR	2,473,833	19,029,573	21,503,406					24
715.5 ACSR								25
715.5 ACSR								26
715.5 ACSR								27
715.5 ACSR								28
1272 ACSR	78,579	2,219,508	2,298,087					29
	40,580		40,580					30
715.5 ACSR	331,539	4,682,879	5,014,418					31
								32
1272 ACSR	704,760	2,141,218	2,845,978					33
795 ACSR								34
795 ACSR								35
	34,835,917	639,955,720	674,791,637	7,787,360	1,544,297	2,710,673	12,042,330	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	04/16/2019	End of 2018/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	Valivue Tap		138.00	138.00	S P Steel	0.79		2
2	Bowmont	Happy Valley	138.00	138.00	S P Steel	8.65		1
3	Antelope	Scoville	138.00	138.00	H Wood	0.12		1
4	American Falls	Wheelon	138.00	138.00	H Wood	1.05		1
5	Kinport	Don #1	138.00	138.00	S Tower	1.27		2
6	Donn	HOKU	138.00	138.00	S P Steel	2.68		1
7	HOKU	Alamed	138.00	138.00	S P Steel	0.22		2
8	HOKU	Alamed	138.00	138.00	S P Steel	0.23		2
9	HOKU	Alamed	138.00	138.00	S P Steel	2.85		1
10	Rockland Jct	Rockland Wind Farm	138.00	138.00	S P Steel	5.18		1
11	King	Justice	138.00	138.00	S P Wood	0.07		1
12	NorthView Tap		138.00	138.00	S P Wood	6.17		1
13	Twin Falls PP Tap		138.00	138.00	H Wood	0.99		1
14	American Falls PP	Amercian Falls Trans ST	138.00	138.00	S P Steel	0.37		1
15	Lower Salmon	King Tie	138.00	138.00	H Wood	0.11		1
16	C J Strike	Strike Jct	138.00	138.00	S Tower	4.30		2
17	Strike Jct	Mountain Home Jct	138.00	138.00	H Wood	23.42		1
18	Strike Jct	Bowmont		138.00	H Wood	0.05		1
19	Strike Jct	Bowmont	138.00	138.00	S Tower	0.36		1
20	Strike Jct	Bowmont	138.00	138.00	H Wood	67.87		1
21	Lucky Peak	Lucky Peak Jct	138.00	138.00	H Wood	4.48		2
22	Bliss	King	138.00	138.00	H Wood	10.51		1
23	Milner Deadend	Milner PP	138.00	138.00	S P Wood	1.30		1
24	Swan Falls Tap		138.00	138.00	H Wood	0.95		1
25								
26								
27								
28	Hines	BPA (Harney)	115.00	115.00	H Wood	3.35		1
29								
30								
31	69 Kv Lines		69.00	69.00	H Wood	205.81		1
32	69 Kv Lines		69.00	69.00	S P Wood	880.67		1
33								
34								
35	46 Kv Lines		46.00	46.00	S P Wood	380.07		1
36					TOTAL	4,754.64	11.02	205

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/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.
795 ACSR		351,497	351,497					1
1272 ACSR	691,728	6,045,286	6,737,014					2
397.5 ACSR		71,018	71,018					3
250 COPPER		105,472	105,472					4
715.5 ACSR	1,174	207,140	208,314					5
1272 ACSR	303,868	4,594	308,462					6
1272 ACSR								7
795 ACSR								8
795 ACSR								9
795 ACSR		-16,973	-16,973					10
1590 ACSR		60,659	60,659					11
715.5 ACSR	105,933	4,125,054	4,230,987					12
250 COPPER	58	63,264	63,322					13
715.5 ACSR		176,736	176,736					14
397.5 ACSR		4,406	4,406					15
715.5 ACSR	1,074	636,545	637,619					16
397.5 ACSR	6,332	2,566,179	2,572,511					17
715.5 ACSR	86,651	4,864,294	4,950,945					18
715.5 ACSR								19
								20
715.5 ACSR	7	287,676	287,683					21
715.5 ACSR	5,620	1,737,275	1,742,895					22
715.5 ACSR	14,968	183,606	198,574					23
397.5 ACSR	17,207	261,512	278,719					24
								25
								26
								27
397.5 ACSR	1,978	63,404	65,382					28
								29
								30
VARIOUS	1,813,793	81,431,839	83,245,632					31
VARIOUS								32
								33
								34
VARIOUS	198,291	20,370,559	20,568,850					35
	34,835,917	639,955,720	674,791,637	7,787,360	1,544,297	2,710,673	12,042,330	36

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/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.
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4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1								
2	Total all lines					4,754.64	11.02	205
3								
4								
5								
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30								
31								
32								
33								
34								
35								
36					TOTAL	4,754.64	11.02	205

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/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.
				7,787,360	1,544,297	2,710,673	12,042,330	1
	34,835,917	639,955,720	674,791,637	7,787,360	1,544,297	2,710,673	12,042,330	2
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								32
								33
								34
								35
	34,835,917	639,955,720	674,791,637	7,787,360	1,544,297	2,710,673	12,042,330	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.: 32 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.: 10 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.: 29 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.: 32 Column: b

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

Schedule Page: 422.1 Line No.: 33 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. 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: 422.4 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: 422.4 Line No.: 4 Column: b

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

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/Q4

TRANSMISSION LINES ADDED DURING YEAR

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

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)	(c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	Star	Lansing	5.50	Steel LD	21.64	1	1
2	Zilog	Can Ada	1.50	Steel LD	12.67	1	1
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
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24							
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31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		7.00		34.31	2	2

TRANSMISSION LINES ADDED DURING YEAR (Continued)

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

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

CONDUCTORS			Voltage KV (Operating)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)	(k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
795	ACSR	TAS & TVS	138		2,215,498	1,536,381		3,751,879	1
795	ACSR	TAS & TVS	138		682,250	861,838		1,544,088	2
									3
									4
									5
									6
									7
									8
									9
									10
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									39
									40
									41
									42
									43
					2,897,748	2,398,219		5,295,967	44

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Schedule Page: 424 Line No.: 1 Column: o

Estimated amounts are reported

Schedule Page: 424 Line No.: 2 Column: o

Estimated amounts are reported

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/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	138.00	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	13.80
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	Black Mesa	distribution	138.00	13.00	
16	Blackfoot	distribution	46.00	13.00	
17	Blackfoot	transmission	161.00	46.00	12.47
18	Blackfoot	distribution	161.00	138.00	12.98
19	Bliss - attended	transmission	138.00	13.80	
20	Blue Gulch	distribution	138.00	35.00	
21	Boise Bench	transmission	230.00	138.00	13.20
22	Boise Bench	distribution	138.00	35.00	
23	Boise Bench	transmission	138.00	69.00	12.98
24	Boise Bench	transmission	230.00	138.00	13.80
25	Boise	distribution	138.00	13.00	
26	Borah	transmission	345.00	230.00	13.80
27	Border	distribution	138.00	13.00	
28	Border	distribution	35.00		
29	Bowmont	distribution	138.00	35.00	
30	Bowmont	transmission	138.00	69.00	12.98
31	Bowmont	transmission	138.00	69.00	12.47
32	Bowmont	transmission	230.00	138.00	13.80
33	Brady	transmission	230.00	138.00	13.80
34	Brady	transmission	138.00	46.00	12.47
35	Brady	distribution	46.00	13.00	
36	Brownlee - attended	transmission	230.00	13.80	
37	Bruneau Bridge	distribution	138.00	35.00	
38	Bruneau Bridge	distribution	138.00	36.20	
39	Buckhorn	distribution	69.00	35.00	
40	Bucyrus	distribution	46.00	7.20	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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.
500	2					1
27	2					2
30	1					3
30	1					4
120	1					5
47	1					6
250	1					7
14	1					8
14	1					9
225	1					10
5	1					11
28	1					12
						13
90	2					14
11	1					15
56	2					16
93	3	1				17
135	1					18
86	3					19
48	2					20
448	2					21
70	2					22
125	3					23
448	2					24
117	3					25
750	3	1				26
11	1					27
5	3					28
30	1					29
46	1					30
47	1					31
600	2					32
312	3					33
		1				34
28	1	4				35
752	5	1				36
30	1					37
45	1					38
37	1					39
7	1	1				40

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/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	Buhl	distribution	46.00	13.20	
2	Burley Rural	distribution	69.00	13.00	
3	Burley Rural	distribution	69.00	13.09	
4	Butler	distribution	138.00	13.09	
5	Caldwell	distribution	138.00	13.00	
6	Caldwell	transmission	230.00	138.00	
7	Caldwell	distribution	138.00	13.09	
8	Caldwell	transmission	138.00	69.00	12.47
9	Caldwell	transmission	230.00	138.00	12.47
10	Camas	distribution	35.00		
11	Camas	distribution	35.00	14.40	
12	Can-Ada	distribution	138.00	13.09	
13	Canyon Creek	distribution	138.00	36.20	
14	Canyon Creek	transmission	138.00	69.00	12.98
15	Cartwright	distribution	138.00	13.00	
16	Cascade Power Plant - attended	transmission	69.00	4.60	
17	Cascade	distribution	69.00	13.00	
18	Cascade	distribution	69.00	13.10	
19	Cascade	distribution	25.00		
20	Chestnut	distribution	138.00	13.00	
21	Chestnut	distribution	138.00	13.09	
22	Cinder	distribution	46.00	13.00	
23	Clear Lake - attended	transmission	46.00	2.40	
24	Cliff	transmission	138.00	46.00	12.50
25	Cliff	transmission	138.00	46.00	12.95
26	Cloverdale	distribution	138.00	13.00	
27	Cloverdale	distribution	138.00	13.09	
28	Council	distribution	69.00	13.00	
29	Crane Creek	distribution	69.00	13.00	
30	Crater	distribution	46.00	13.00	
31	Dale	distribution	46.00	4.60	
32	Dale	distribution	46.00	13.00	
33	Dale	distribution	69.00	13.00	
34	Dale	distribution	138.00	36.20	
35	Dale	transmission	138.00	46.00	12.47
36	Danskin- attended	transmission	230.00	18.00	
37	Danskin- attended	transmission	230.00	138.00	13.80
38	Danskin- attended	distribution	18.00	4.16	
39	Danskin- attended	transmission	138.00	12.00	
40	Danskin- attended	distribution	35.00	13.80	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT: Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
		1				1
		1				2
45	1					3
90	2					4
28	1					5
200	1					6
45	1					7
140	3					8
200	1					9
5	3	1				10
10	3	1				11
45	1					12
45	1					13
20	1					14
11	1					15
16	1					16
7	1					17
14	1					18
5	1					19
45	1					20
45	1					21
11	1					22
5	1					23
21	2	1				24
10	1					25
45	1					26
45	1					27
14	1					28
11	1					29
11	1					30
		1				31
		7				32
		1				33
45	1					34
47	1					35
233	1					36
300	1					37
6	1					38
160	2					39
5	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	04/16/2019	End of 2018/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	Deen	distribution	46.00	13.00	
2	Dietrich	distribution	46.00	13.09	
3	Don	distribution	138.00	7.60	
4	Don	distribution	138.00	13.20	
5	Don	distribution	138.00	13.00	
6	DRAM	distribution	138.00	13.09	
7	DRAM	transmission	230.00	138.00	13.80
8	DRAM	distribution	138.00	12.47	
9	DRAM	distribution	138.00	13.00	
10	Duffin	distribution	138.00	35.00	
11	Eagle	distribution	138.00	13.09	
12	Eastgate	distribution	138.00		
13	Eastgate	distribution	138.00	13.00	
14	Eckert	distribution	138.00	36.20	
15	Eden	distribution	138.00	36.20	
16	Eden	transmission	138.00	46.00	12.98
17	Elkhorn	distribution	138.00	12.47	
18	Elkhorn	distribution	138.00	13.00	
19	Elmore	distribution	138.00	35.00	
20	Elmore	transmission	138.00	69.00	12.50
21	Elmore	transmission	138.00	69.00	12.98
22	Emmett	distribution	138.00		
23	Emmett	transmission	138.00	69.00	12.47
24	Falls	distribution	46.00	13.00	
25	Filer	distribution	46.00	13.00	
26	Flat Top	distribution	46.00	13.00	
27	Flying H	distribution	69.00	2.40	
28	Fort Hall	distribution	46.00	13.00	
29	Fossil Gulch	distribution	138.00	35.00	
30	Fremont	transmission	138.00	46.00	12.50
31	Gary	distribution	138.00	13.09	
32	Gary	distribution	138.00	13.00	
33	Gem	distribution	69.00	13.00	
34	Gem	distribution	69.00		
35	Glenns Ferry	distribution	138.00	13.00	
36	Gooding Rural	distribution	46.00	13.00	
37	Golden Valley	distribution	69.00	13.00	
38	Goshen	transmission	345.00	161.00	69.00
39	Gowen Substation	distribution	138.00	35.00	
40	Grindstone	distribution	35.00		

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.
11	1					1
14	1					2
		1				3
180	6	1				4
44	1					5
168	6					6
212	2					7
28	1					8
28	1					9
60	2					10
67	2					11
45	1					12
30	1					13
30	1					14
45	1					15
20	1					16
11	1					17
11	1					18
28	1					19
25	1					20
20	1					21
45	1					22
47	1					23
28	2					24
14	1					25
17	2					26
20	2					27
14	1	1				28
28	1					29
67	3	1				30
37	1					31
28	1					32
14	1	1				33
14	1					34
11	1					35
20	2					36
14	1	1				37
908	4					38
45	1					39
7	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	04/16/2019	End of 2018/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	Grindstone	distribution	35.00	2.40	
2	Grove	distribution	138.00	13.09	
3	Grove	distribution	138.00	13.00	
4	Hagerman	distribution	46.00	13.00	
5	Hagerman	distribution	69.00	13.00	
6	Hailey	distribution	138.00	13.00	
7	Happy Valley	distribution	138.00	13.09	
8	Haven	distribution	138.00	35.00	
9	Haven	transmission	138.00	46.00	
10	Hemingway	transmission	500.00	230.00	34.50
11	Hewlett Packard	distribution	138.00	13.00	
12	Hidden Springs	distribution	138.00	13.00	
13	Highland	distribution	138.00	13.00	
14	Hill	distribution	138.00	13.00	
15	Hillsdale	distribution	138.00		
16	Homedale	distribution	69.00	13.00	
17	Horse Flat	transmission	230.00	138.00	13.80
18	Horseshoe Bend	distribution	35.00		
19	Horseshoe Bend	distribution	69.00	36.20	
20	Horseshoe Bend	distribution	69.00	25.00	
21	Huston	distribution	69.00	13.00	
22	Hulen	distribution	46.00	13.00	
23	Hunt	transmission	230.00	138.00	13.80
24	Hydra	distribution	138.00	36.20	
25	Island	distribution	69.00	13.00	
26	Jefferson	transmission	161.00		
27	Jerome	distribution	138.00	13.00	
28	Jerome	distribution	138.00	13.09	
29	Julion Clawson	distribution	138.00	35.00	
30	Joplin	distribution	138.00	13.00	
31	Joplin	distribution	138.00	36.20	
32	Justice	transmission	230.00	138.00	13.80
33	Karcher	distribution	138.00	13.00	
34	Kenyon	distribution	69.00	13.00	
35	Ketchum	distribution	138.00	13.00	
36	Kimberly	distribution	138.00	13.09	
37	Kinport	transmission	161.00	46.00	13.20
38	Kinport	transmission	230.00	138.00	12.47
39	Kinport	transmission	230.00	138.00	13.80
40	Kinport	transmission	345.00	230.00	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.
7	1					1
90	2					2
45	1					3
14	1					4
6	1					5
37	1					6
30	1					7
20	1					8
47	1					9
1000	3	1				10
37	1					11
11	1					12
30	1					13
73	2					14
45	1					15
34	2					16
100	1					17
7	1					18
22	1					19
7	1					20
14	1					21
14	1					22
336	3					23
90	2					24
20	1					25
						26
37	1					27
37	1					28
56	2					29
28	1					30
45	1					31
300	1					32
20	1					33
25	2					34
75	2					35
45	1	1				36
		7				37
300	1					38
300	1					39
1000	3	1				40

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/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	Kramer	distribution	138.00	35.00	
2	Kramer	distribution	138.00	36.20	
3	Kuna	distribution	138.00	13.09	
4	Lake	distribution	69.00	13.00	
5	Lake Fork	distribution	138.00	36.20	
6	Lake Fork	transmission	138.00	69.00	12.50
7	Lamb	distribution	138.00	13.00	
8	Langley Gulch- attended	transmission	230.00	138.00	13.80
9	Langley Gulch- attended	transmission	230.00		
10	Langley Gulch- attended	transmission	230.00	150.00	
11	Lansing	distribution	138.00	13.09	
12	Lincoln	distribution	138.00	13.09	
13	Linden	distribution	138.00	13.00	
14	Locust	distribution	138.00	36.20	
15	Locust	transmission	230.00	138.00	13.80
16	Lower Malad - attended	transmission	138.00	7.20	
17	Lower Salmon - attended	transmission	138.00	13.80	
18	Map Rock	distribution	69.00	13.00	
19	McCall	distribution	138.00	13.09	
20	McCall	distribution	138.00	36.20	
21	Melba	distribution	69.00	13.00	
22	Meridian	distribution	138.00	13.00	
23	Micron	distribution	138.00	13.09	
24	Micron	distribution	138.00	13.00	
25	Midpoint	transmission	230.00	138.00	13.80
26	Midpoint	transmission	345.00	230.00	13.80
27	Midpoint	transmission	500.00	345.00	
28	Midrose	distribution	138.00	13.09	
29	Milner	transmission	138.00	69.00	12.47
30	Milner	distribution	69.00	46.00	6.90
31	Milner	distribution	138.00	35.00	
32	Milner PP - attended	transmission	138.00	13.80	
33	Moonstone	distribution	138.00	35.00	
34	Mora	distribution	138.00	13.09	
35	Mora	distribution	138.00	36.20	
36	Moreland	distribution	46.00	13.00	
37	Mountain Home	distribution	69.00	13.00	
38	Mountain Home Air Force Base	distribution	69.00	13.00	
39	Mountain Home Air Force Base	distribution	138.00	13.00	
40	Nampa	transmission	230.00	138.00	13.80

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/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.
20	1					1
30	1					2
45	1					3
14	1					4
30	1					5
20	1					6
30	1					7
636	2					8
410	2					9
		1				10
40	1					11
14	1					12
58	2					13
134	3					14
600	2					15
16	1					16
70	4					17
13	1					18
22	1					19
30	1					20
11	1					21
60	2					22
40	2					23
40	2					24
200	1					25
1400	2	1				26
1500	3	1				27
45	1					28
125	3	1				29
8	3	1				30
50	2					31
60	1					32
20	1					33
45	1					34
45	1					35
28	2					36
28	1					37
		1				38
34	1					39
300	1					40

Name of Respondent Idaho Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/16/2019	Year/Period of Report End of 2018/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	Nampa	distribution	138.00	13.00	
2	New Meadows	distribution	138.00	36.20	
3	New Plymouth	distribution	69.00	13.00	
4	Northview	distribution	138.00		
5	Notch Butte	distribution	138.00	13.09	
6	Orchard	distribution	69.00	36.20	
7	Orchard	distribution	69.00		
8	Parma	distribution	69.00	13.00	
9	Parma	distribution	69.00	35.00	
10	Paul	distribution	138.00	35.00	
11	Paul	distribution	138.00	36.20	
12	Payette	distribution	138.00		
13	Pingree	transmission	138.00	46.00	12.50
14	Pingree	distribution	138.00	35.00	
15	Pleasant Valley	distribution	138.00	35.00	
16	Pleasant Valley	distribution	138.00	36.20	
17	Pocatello	distribution	46.00	13.00	
18	Pocket	distribution	138.00	36.20	
19	Poleline	distribution	138.00	13.09	
20	Populus	transmission	345.00		
21	Portneuf	distribution	138.00	35.00	
22	Portneuf	distribution	46.00	35.00	
23	Rockford	distribution	46.00	13.00	
24	Russett	distribution	138.00	13.00	
25	Sailor Creek	distribution	138.00	2.40	
26	Sailor Creek	distribution	138.00	35.00	
27	Salmon	distribution	69.00	13.00	
28	Salmon	distribution	69.00	34.50	12.47
29	Salmon	distribution	69.00	7.20	
30	Shoshone	distribution	46.00	13.09	
31	Shoshone	distribution	46.00	7.20	
32	Shoshone Falls - attended	transmission	46.00	2.30	
33	Shoshone Falls - attended	transmission	46.00	6.60	
34	Silver	distribution	138.00	35.00	
35	Simplot	distribution	138.00	13.00	
36	Sinker Creek	distribution	138.00	35.00	
37	Siphon	distribution	138.00	35.00	
38	South Park	distribution	46.00	13.00	
39	Spring Valley	distribution	138.00	12.47	
40	Star	distribution	138.00	13.09	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/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.
87	3					1
22	1					2
13	1					3
45	1					4
14	1					5
8	1					6
33	1					7
14	1					8
20	1					9
30	1	1				10
45	1					11
45	1					12
67	3					13
34	2					14
30	1					15
45	1					16
60	2					17
45	1					18
30	1					19
						20
30	1					21
		1				22
25	2					23
30	1					24
21	2					25
28	1					26
14	1	4				27
10	3	1				28
		1				29
		1				30
2	3					31
		1				32
14	1					33
20	1					34
53	2					35
20	1					36
55	2					37
14	1					38
11	1					39
30	1					40

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	Starkey	transmission	138.00	69.00	12.47
2	State	distribution	69.00	13.00	
3	Sterling	distribution	46.00	13.00	
4	Stoddard	distribution	138.00	13.00	
5	Strike Power Plant - attended	transmission	138.00	13.80	
6	Sugar	distribution	138.00	35.00	
7	Swan Falls - attended	transmission	138.00	6.90	
8	Taber	distribution	46.00	13.00	
9	Tamarack	distribution	138.00	2.40	
10	Ten Mile	distribution	138.00	13.09	
11	Terry	distribution	138.00	13.09	
12	Terry	distribution	138.00	13.00	
13	Thousand Springs - attended	transmission	46.00	7.20	
14	Three Mile Knoll	transmission	345.00		
15	Toponis	distribution	138.00	33.00	
16	Twin Falls	distribution	138.00	13.09	
17	Twin Falls	transmission	138.00	46.00	12.98
18	Twin Falls PP - attended	transmission	138.00	7.20	
19	Twin Falls PP - attended	transmission	138.00	13.20	
20	Tyhee	distribution	46.00	13.00	
21	Upper Malad - attended	transmission	45.00	7.20	
22	Upper Salmon- attended	transmission	138.00	7.20	
23	Ustick	distribution	138.00	13.00	
24	Vallivue	distribution	138.00	13.09	
25	Victory	distribution	138.00	13.00	
26	Victory	distribution	138.00	13.09	
27	Ware	distribution	69.00	13.00	
28	Weiser	distribution	69.00	13.00	
29	Weiser	transmission	138.00	69.00	12.47
30	Wilder	distribution	69.00	13.00	
31	Willis	distribution	138.00	13.09	
32	Willow Creek	distribution	138.00	13.00	
33	Wye	distribution	138.00	13.00	
34	Wye	distribution	138.00	13.09	
35	Zilog	distribution	138.00	13.09	
36					
37					
38	The above are all State of Idaho				
39					
40	Montana:				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
30	1					1
58	2					2
11	2					3
28	1					4
104	3					5
28	2					6
34	1					7
6	1					8
11	1					9
90	2					10
20	1					11
50	2					12
8	1					13
						14
30	1					15
82	2					16
50	2					17
13	1					18
72	1					19
14	1					20
8	1					21
42	4					22
77	2					23
30	1					24
45	1					25
30	1					26
20	1	1				27
28	2	1				28
42	1					29
14	1					30
30	1					31
11	1					32
60	2					33
37	1					34
45	1					35
						36
						37
						38
						39
						40

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	Mill Creek	transmission	230.00		
2	Peterson	transmission	230.00	69.00	13.20
3					
4	Nevada:				
5	Valmy - attended	transmission	345.00	18.00	
6	Valmy - attended	transmission	345.00	22.00	
7	Wells	transmission	138.00	69.00	13.00
8					
9	Oregon:				
10	Adrian	distribution	69.00	13.00	
11	Boardman - attended	transmission	500.00	24.00	
12	Boardman - attended	transmission	230.00	7.20	
13	Boardman - attended	transmission	24.00	7.20	
14	Burns	transmission	500.00		
15	Cairo	distribution	69.00	13.00	
16	Hells Canyon - attended	transmission	230.00	13.80	
17	Hells Canyon - attended	distribution	69.00	0.50	
18	Hines	transmission	138.00	115.00	12.47
19	Hurricane	transmission	230.00		
20	Jacobson Gulch	distribution	69.00	2.40	
21	Malheur Butte	distribution	69.00	34.50	
22	Nyssa	distribution	69.00	13.00	
23	Ontario	distribution	138.00	13.00	
24	Ontario	transmission	138.00	69.00	12.47
25	Ontario	transmission	230.00	138.00	13.80
26	Ontario	transmission	138.00	69.00	12.98
27	Ontario	transmission	138.00	69.00	13.09
28	Ontario	transmission	138.00	69.00	12.50
29	Ore-Ida	distribution	69.00	13.00	
30	Oxbow - attended	transmission	138.00	69.00	13.00
31	Oxbow - attended	transmission	230.00	13.80	
32	Oxbow - attended	transmission	230.00	138.00	13.80
33	Quartz	transmission	138.00	69.00	12.50
34	Quartz	transmission	230.00	138.00	12.98
35	Quartz	transmission	138.00	69.00	12.98
36	Summer Lake	transmission	500.00		
37	Vale	distribution	69.00	13.00	
38					
39	Washington:				
40	Walla Walla	transmission	230.00		

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
30	3	1				2
						3
						4
315	1					5
300	1					6
25	3	1				7
						8
						9
11	1					10
685	3					11
55	1					12
55	1					13
						14
20	1					15
560	3					16
1	1					17
50	1					18
						19
11	1					20
11	3	1				21
28	2					22
67	2	1				23
47	1					24
400	2					25
93	2					26
		1				27
		1				28
28	1					29
13	3	1				30
274	2	1				31
100	1					32
25	1					33
167	3	1				34
20	1					35
						36
14	1					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) 04/16/2019	Year/Period of Report End of 2018/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					
2	Wyoming:				
3	Jim Bridger - attended	transmission	345.00	22.00	34.50
4					
5					
6					
7					
8					
9	Transformers-distribution substations under 10,000				
10	KVA 61 unattended.				
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Idaho Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/16/2019	End of 2018/Q4

SUBSTATIONS (Continued)

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

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
						1
						2
2244	4					3
						4
						5
						6
						7
						8
						9
214						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

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. 100% of the capacity is reported.

Schedule Page: 426 Line No.: 1 Column: f

For all of column F:
Top rating capacity reported unless otherwise noted.

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. 100% of the capacity reported.

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.: 26 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. 100% of the capacity is reported.

Schedule Page: 426.2 Line No.: 38 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. 100% of the capacity reported.

Schedule Page: 426.3 Line No.: 10 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. 100% of the capacity is reported.

Schedule Page: 426.3 Line No.: 26 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.: 40 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. 100% of the capacity is reported.

Schedule Page: 426.4 Line No.: 27 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. 100% of the capacity is reported.

Schedule Page: 426.5 Line No.: 20 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: 426.6 Line No.: 14 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: 426.7 Line No.: 1 Column: a

Idaho Power has 32% ownership interest in certain transmission related equipment located at Northwestern Energy's Mill Creek Station.

Schedule Page: 426.7 Line No.: 5 Column: a

Jointly owned with Sierra Pacific Power Company, d/b/a NV Energy. Idaho Power has a 50% share of ownership. 100% of the capacity reported.

Schedule Page: 426.7 Line No.: 6 Column: a

Jointly owned with Sierra Pacific Power Company, d/b/a NV Energy. Idaho Power has a 50% share of ownership. 100% of the capacity reported.

Schedule Page: 426.7 Line No.: 11 Column: a

Jointly owned with Portland General Electric, Power Resources Cooperative and BA Leasing BCS, LLC. Idaho Power has a 10% share of the jointly owned capacity. 100% of the capacity is reported.

Schedule Page: 426.7 Line No.: 12 Column: a

Jointly owned with Portland General Electric, Power Resources Cooperative and BA Leasing BCS, LLC. Idaho Power has a 10% share of the jointly owned capacity. 100% of the capacity is reported.

Schedule Page: 426.7 Line No.: 13 Column: a

Jointly owned with Portland General Electric, Power Resources Cooperative and BA Leasing BCS, LLC. Idaho Power has a 10% share of the jointly owned capacity. 100% of the capacity is reported.

Schedule Page: 426.7 Line No.: 14 Column: a

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.: 19 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.: 36 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.: 40 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: 426.8 Line No.: 3 Column: a

Jointly owned with PacificCorp. Idaho Power has a 33.3% share of ownership. 100% of the capacity is reported.

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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	04/16/2019	End of 2018/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	450,915
22			922000	28,844
23				
24				
25				
26				
27				
28				
29				
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41				
42				

ANNUAL REPORT
OREGON SUPPLEMENT TO FERC FORM 1

for
MULTI-STATE ELECTRIC COMPANIES

INDEX

STATE OF OREGON STATEMENT OF OPERATING INCOME FOR THE YEAR

Line No.	Account (a)	(Ref.) Page No. (b)	ELECTRIC UTILITY Current Year (c)	ELECTRIC UTILITY Previous Year (d)
1	UTILITY OPERATING INCOME			
2	Operating Revenues (400)	2	$ 63,835,278	$ 60,165,308
3	Operating Expenses			
4	Operation Expenses (401)	8-11	36,138,421	35,542,454
5	Maintenance Expenses (402)	8-11	3,497,859	3,083,590
6	Depreciation Expense (403)	12	6,543,263	6,695,418
7	Amort. & Depl. of Utility Plant (404-405)	12	287,950	267,292
8	Amort. of Utility Plant Acq. Adj. (406)	12	616	1,386
9	Amort. of Property Losses, Unrecovered Plant and Regulatory Study Costs (407-411)	12	(6,355)	(5,568)
10	Accretion Expense (411)	12	10,126	9,829
11	Amort. of Conversion Expenses (407)	12		
12	Taxes Other Than Income Taxes (408.1)	13	2,380,283	2,418,153
13	Regulatory Debits/Credits	14	219,223	1,003,154
14	Income Taxes - Federal (409.1)	14	1,023,370	1,229,795
15	- Other (409.1)	15	(947)	334,362
16	Provision for Deferred Inc. Taxes (410.1)	16-23	1,840,748	1,972,350
17	(Less) Provision for Deferred Income Taxes - Cr.(411.1)	16-23	(2,070,083)	(2,892,837)
18	Investment Tax Credit Adj. - Net (411.4)	24	224,387	319,752
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)		50,088,861	49,979,129
22	Net Utility Operating Income (Total of line 2 less 20)		$ 13,746,417	$ 10,186,180

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) regul used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (S Account 442 of the Uniform System of Accounts. Ex 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..	$ 17,959,995	$ 19,292,567	176,846	193,127	13,435	13,423	2
3	(442) Commercial and Industrial Sales							3
4	Small (or Commercial) (See Instr. 4) (1)...............	20,244,849	18,585,147	222,754	219,243	5,578	5,473	4
5	Large (or Industrial) (See Instr. 4) (2)...................	17,383,277	15,812,491	278,020	268,873	7	7	5
6	(444) Public Street and Highway Lighting..............	136,613	143,799	912	924	34	34	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................	55,724,734*	53,834,005*	678,531 **	682,167	19,054	18,937	10
11	(447) Sales for Resale - Opportunity Non-Firm........	3,665,888	1,176,057	132,620	55,333			11
12	TOTAL Sales of Electricity................................	59,390,623	55,010,062	811,152	737,499	19,054	18,937	12
13	(Less) (449.1) Provision for Rate Refunds..............	564,308	-					13
14	TOTAL Revenue Net of Provision for Refunds....	58,826,314	55,010,062					14
15	Other Operating Revenues							
16	(450) Forfeited Discounts.......................................							
17	(451) Miscellaneous Service Revenues..................	86,216	82,758					
18	(453) Sales of Water and Water Power..................							
19	(454) Rent from Electric Property...........................	772,357	710,042					
20	(455) Interdepartmental Rents………………………							
21	(456) Other Electric Revenues...............................	4,150,391	3,820,429					
22								
23								
24								
25	TOTAL Other Operating Revenues....................	5,008,964	4,613,230					
26	TOTAL Electric Operating Revenues.................	$ 63,835,278	$ 59,623,291					

* Includes -$42,850.00 unbilled revenues.

** Includes -.919 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 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 "Electri 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 revenı 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	178,156	$ 17,738,562	13,435	13,261	9.96
3	03 - Residential-Mastered Metered					
4	05 - Residential - TOD					
5	15 - Dusk to Dawn customer Lighting	184	51,275			27.87
6	**Residential - Billed**	**178,340**	**17,789,837**	**13,435**	**13,274**	**9.98**
7	Residential - Unbilled	(1,494)	(88,444)			5.92
8	Bridger Depr & Boardman Decomm		258,601			
9	**Total 440**	**176,846**	**17,959,994**	**13,435**	**13,163**	**10.16**
10						
11	442 - Commercial and Industrial Sales:					
12	07 - General Service	18,193	1,951,914	2,554	7,125	10.73
13	09P - General Service	15,163	1,080,427	5	2,844,841	7.13
14	09S - General Service	115,147	9,173,938	901		
15	09T - General Service	2,848	186,385	1		
16	15 - Dusk to dawn customer lighting	249	56,765	0		22.80
17	19P - Uniform rate contracts	165,189	10,507,732	6	27,531,567	6.36
18	19S - Uniform rate contracts	0	0	0		
19	19T - Uniform rate contracts	110,488	6,432,020	1		
20	24S - Irrigation and soil drainage pump	71,996	7,060,816	2,115	34,038	9.81
21	40 - General Service	5	463	2	2,500	9.26
22	**Commercial & Industrial - Billed**	**499,279**	**36,450,462**	**5,585**	**89,391**	**7.30**
23	Commercial & Industrial - Unbilled	1,494	53,619			3.59
24	Bridger Depr & Boardman Decomm		1,124,044			
25	**Total 442**	**500,773**	**37,628,126**	**5,585**	**89,659**	**7.51**
26						
27						
28	444 - Public Street and Highway Lighting:					
29	40 - General Service					
30	41 - Municipal street lighting	891	143,232	26	34,269	16.08
31	42 - Municipal traffic control signal light	22	2,138	8	2,750	9.72
32	**Public Street & Highway lighting billed**	**913**	**145,370**	**34**	**26,853**	**15.92**
33	Public St & Highway lighting-unbilled	(1)	(8,026)			
34	Bridger Depr & Boardman Decomm		(731)			
35	**Total 444**	**912**	**136,613**	**34**	**26,824**	**14.98**
36						
37						
38						
39						
40						
41	Total Billed	678,532	55,767,584	19,054	35,611	8.22
42	Total Unbilled Rev. (See Instr. 6)	(1)	(42,851)			
43	TOTAL	678,531	55,724,733	19,054	35,611	8.22

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									

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
				3,665,888		$ 3,665,888	3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
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							24
							25
							26

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

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

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

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

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

Line No.	Name of Lessee or Department (a)	Description of Property (b)	Amount of Revenue For Year (c)
21	Various	Substation Equipment Rental	$ 141,822
22			
23	"	Transformer Rentals - Dist	657
24			
25	"	Line Rentals	-
26			
27	"	Cogeneration	73,071
28			
29	"	Pole Attachments	116,077
30			
31	"	Facilities Charges	406,317
32			
33	"	Other Rentals	30,784
34			
35	"	Water Lease	3,630
36			
37	"		
38	Total Account 454		$ 772,357

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	$ 86,216
7		
8	Account 456	
9		
10	Transmission for Others - Network	$ 463,128
11	Transmission - Point-to-Point and Other	1,639,621
12	Photovoltaic Station Service	-
13	DSM Rider Funds	2,039,947
14	Sierra Pacific Usage Charge	5,834
15	Antelope	-
16	Miscellaneous	1,862
17		
18		
19		
20	Total Account 456	$ 4,150,391
21		
22		
23		

ALLOCATED ELECTRIC OPERATION AND MAINTENANCE EXPENSES - OREGON

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	(1) POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	$ 49,422	$ 41,682
5	(501) Fuel	5,350,133	5,008,233
6	(502) Steam Expenses	459,077	394,622
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	86,531	64,801
10	(506) Miscellaneous Steam Power Expenses	374,651	498,066
11	(507) Rents	10,289	14,009
12	(509) Allowances		
13	TOTAL Operation (Enter Total of lines 4 thru 12)	6,330,103	6,021,413
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	8,747	2,352
16	(511) Maintenance of Structures	14,332	18,757
17	(512) Maintenance of Boiler Plant	502,354	512,057
18	(513) Maintenance of Electric Plant	210,489	201,055
19	(514) Maintenance of Miscellaneous Steam Plant	292,965	252,773
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	1,028,886	986,994
21	TOTAL Power Production Expenses-Steam Power (Enter Total of lines 13 and 20)	7,358,990	7,008,406
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	232,824	244,264
45	(536) Water for Power	374,215	249,442
46	(537) Hydraulic Expenses	631,122	639,182
47	(538) Electric Expenses	79,531	82,706
48	(539) Miscellaneous Hydraulic Power Generation Expenses	229,724	352,240
49	(540) Rents	10,119	10,297
50	TOTAL Operation (Enter Total of lines 44 thru 49)	1,557,534	1,578,131

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	$ 3,836	$ 4,004
54	(542) Maintenance of Structures	30,560	48,512
55	(543) Maintenance of Reservoirs, Dams, and Waterways	13,641	35,003
56	(544) Maintenance of Electric Plant	129,790	82,162
57	(545) Maintenance of Miscellaneous Hydraulic Plant	109,385	120,080
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	287,212	289,760
59	TOTAL Power Production Expenses-Hydraulic Power (Enter Total of lines 50 and 58)	1,844,746	1,867,892
61	Operation		
62	(546) Operation Supervision and Engineering	26,617	29,297
63	(547) Fuel	818,514	1,760,883
64	(548) Generation Expenses	195,283	184,626
65	(549) Miscellaneous Other Power Generation Expenses	57,691	42,027
66	(550) Rents	-	-
67	TOTAL Operation (Enter Total of lines 62 thru 66)	1,098,105	2,016,834
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	2	10
70	(552) Maintenance of Structures	8,830	14,271
71	(553) Maintenance of Generating and Electric Plant	5,476	27,405
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	108,323	94,806
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	122,632	136,491
74	TOTAL Power Production Expenses-Other Power (Enter Total of lines 67 and 73)	1,220,736	2,153,325
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	13,322,069	11,333,025
77	(556) System Control and Load Dispatching	219	123
78	(557) Other Expenses	110,667	677,300
79	TOTAL Other Power Supply Expenses (Enter Total of lines 76 thru 78)	13,432,954	12,010,448
80	TOTAL Power Production Expenses (Enter Total of lines 21, 41, 59, 74, and 79)	23,857,426	23,040,070
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	136,354	134,412
84	(561) Load Dispatching	218,479	208,180
85	(562) Station Expenses	117,315	123,203
86	(563) Overhead Line Expenses	36,119	45,669
87	(564) Underground Line Expenses		
88	(565) Transmission of Electricity by Others	166,823	212,057
89	(566) Miscellaneous Transmission Expenses	623	1
90	(567) Rents	111,382	204,023
91	TOTAL Operation (Enter Total of lines 83 thru 90)	787,094	927,545
92	Maintenance		
93	(568) Maintenance Supervision and Engineering	29,264	6,602
94	(569) Maintenance of Structures	43,939	41,119
95	(570) Maintenance of Station Equipment	70,714	82,132
96	(571) Maintenance of Overhead Lines	34,203	37,698
97	(572) Maintenance of Underground Lines		
98	(573) Maintenance of Miscellaneous Transmission Plant	-	143
99	(575) Regional Market Expense - EIM	16,918	
100	TOTAL Maintenance (Enter Total of lines 93 thru 98)	195,038	167,694
101	TOTAL Transmission Expenses (Enter Total of lines 91 and 99)	982,132	1,095,239
102	Operation		
103	(580) Operation Supervision and Engineering	193,558	185,421

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	$ 165,089	$ 167,843
106	(582) Station Expenses	65,091	65,744
107	(583) Overhead Line Expenses	287,179	367,043
108	(584) Underground Line Expenses	47,960	51,462
109	(585) Street Lighting and Signal System Expenses	7,260	5,531
110	(586) Meter Expenses	154,207	167,166
111	(587) Customer Installations Expenses	96,819	95,901
112	(588) Miscellaneous Distribution Expenses	210,092	303,418
113	(589) Rents	51,200	16,800
114	TOTAL Operation (Enter Total of lines 103 thru 113)	1,278,456	1,426,329
115	Maintenance		
116	(590) Maintenance Supervision and Engineering	25,729	(72,428)
117	(591) Maintenance of Structures	(45)	-
118	(592) Maintenance of Station Equipment	186,320	164,269
119	(593) Maintenance of Overhead Lines	1,282,401	1,031,632
120	(594) Maintenance of Underground Lines	9,951	10,650
121	(595) Maintenance of Line Transformers	1,729	960
122	(596) Maintenance of Street Lighting and Signal Systems	27,103	25,840
123	(597) Maintenance of Meters	30,750	33,498
124	(598) Maintenance of Miscellaneous Distribution Plant	16,109	18,066
125	TOTAL Maintenance (Enter Total of lines 116 thru 124)	1,580,045	1,212,487
126	TOTAL Distribution Expenses (Enter Total of lines 114 and 125)	2,858,501	2,638,816
127	4. CUSTOMER ACCOUNTS EXPENSES		
128	Operation		
129	(901) Supervision	67,121	48,995
130	(902) Meter Reading Expenses	460,859	332,214
131	(903) Customer Records and Collection Expenses	479,938	496,503
132	(904) Uncollectible Accounts	225,836	401,264
133	(905) Miscellaneous Customer Accounts Expenses	(0)	(54)
134	TOTAL Customer Accounts Expenses (Enter Total of lines 129 thru 133)	1,233,754	1,278,922
135	5. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
136	Operation		
137	(907) Supervision	42,418	43,062
138	(908) Customer Assistance Expenses	2,245,519	2,316,690
139	(909) Informational and Instructional Expenses	11,752	15,531
140	(910) Miscellaneous Customer Service and Informational Expenses	33,092	33,547
141	TOTAL Cust. Service and Informational Expenses (Enter Total of lines 137 thru 140)	2,332,781	2,408,830
142	6. SALES EXPENSES		
143	Operation		
144	(911) Supervision		
145	(912) Demonstrating and Selling Expenses	-	-
146	(913) Advertising Expenses		
147	(916) Miscellaneous Sales Expenses		
148	TOTAL Sales Expenses (Enter Total of lines 144 thru 147)	-	-
149	7. ADMINISTRATIVE AND GENERAL EXPENSES		
150	Operation		
151	(920) Administrative and General Salaries	4,175,683	3,706,766
152	(921) Office Supplies and Expenses	695,269	662,544
153	(922) Administrative Expenses Transferred-Credit	(1,373,571)	(1,301,361)

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	$ 364,038	$ 317,324
156	(924) Property Insurance	123,912	133,126
157	(925) Injuries and Damages	264,068	264,703
158	(926) Employee Pensions and Benefits	2,742,526	3,371,500
159	(927) Franchise Requirements	-	-
160	(928) Regulatory Commission Expenses	897,860	535,629
161	(929) Duplicate Charges-Cr		
162	(930.1) General Advertising Expenses	28,383	17,081
163	(930.2) Miscellaneous General Expenses	169,472	166,705
164	(931) Rents	-	(15)
165	TOTAL Operation (Enter Total of lines 151 thru 164)	8,087,641	7,874,002
166	Maintenance		
167	(935) Maintenance of General Plant	284,046	290,163
168	TOTAL Administrative and General Expenses (Enter Total of lines 165 thru 167)	8,371,687	8,164,165
169	TOTAL Electric Operation and Maintenance Expenses (Enter Total of lines 80, 100, 126, 134, 141, 148, and 168)	$ 39,636,280	$ 38,626,044

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	$ 6,330,103	$ 1,028,886	$ 7,358,990
173	Nuclear power			
174	Hydraulic - Conventional	1,557,534	287,212	1,844,746
175	Hydraulic - Pumped Storage			
176	Other power	1,098,105	122,632	1,220,736
	Other Power Supply Expenses	13,432,954	-	13,432,954
177	Total Power Production Expenses	22,418,696	1,438,730	23,857,426
178	Transmission Expenses	787,094	195,038	982,132
179	Distribution Expenses	1,278,456	1,580,045	2,858,501
180	Customer Accounts Expenses	1,233,754	-	1,233,754
181	Customer Service and Informational Expenses	2,332,781	-	2,332,781
182	Sales Expenses	-	-	-
183	Administrative and General Expenses	8,087,641	284,046	8,371,687
184	Total Electric Operation and Maintenance Expenses	$ 36,138,421	$ 3,497,859	$ 39,636,280

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..	$ -	$ -		$ -
2	Steam Production Plant...	1,937,171	-		1,937,171
3	Nuclear Production Plant..				-
4	Hydraulic Production Plant - Conventional...............	668,129	-		668,129
5	Hydraulic Production Plant - Pumped Storage.........				
6	Other Production Plant..	658,519	-		658,519
7	Transmission Plant..	916,128	-		916,128
8	Distribution Plant...	1,698,621	-		1,698,621
9	General Plant...	652,091	-		652,091
10	Depreciation on Disallowed Costs............................	(12,357)	-		(12,357)
11	Boardman ARO Depreciation....................................	24,960			24,960
12	ARO Accretion	10,126			10,126
13	TOTAL.................................	$ 6,553,388	$ -		$ 6,553,388

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 JOOA SWAP TRANS COST			$ 615.97
Account 411			
411.6			$ -
411.7			-
411.8 - Green Tags and Emissions			(6,355)
			$ (5,739)

ALLOCATED TAXES, OTHER THAN INCOME TAXES (ACCOUNT 408.1) - OREGON

	KIND OF TAX	Amount
1	Federal Taxes:	
2	FICA	$ 733,106
3	FUTA	4,441
4	Less: Payroll Deduction and Loading	(749,185)
5	State Taxes:	
6	Ad Valorem	1,199,021
7	Licenses - Hydro Projects	179
8	Regulatory Commission Fees	255,980
9	Franchise Taxes	837,813
10	State Unemployment Taxes	11,638
11	Hydro Generation KWH Tax	87,290
12	Canada Sales Tax	0
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23	TOTAL (Must agree with page 1, line 12.)	2,380,283

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	$ 63,835,278
2	Operations and Maintenance Expenses	39,636,280
3	Taxes Other Than Income	2,380,283
4	Regulatory Debits/Credits	219,223
5	State Income (Excise) Tax	256,138
6	Interest	4,019,212
7	Federal Income Tax Depreciation	6,543,263
8	Other Line items to Derive Taxable Income	10,126
9	Amortization of Limited-Term Plant	282,211
10		
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24	Federal Tax Net Income	$ 10,488,543
25		
26		
27	Show Computation of Tax:	
28		
29	Federal Income Tax @ 21%	$ 2,202,594
30	FIN 48 Adjustment	-
31	Prior Years' Tax Adjustment	(1,226,311)
32	Total Federal Income Tax Before Other Adjustments	976,283
33		
34	Other Tax Adjustments	
35	Allowance for AFUDC	$ 1,432,393
36	Income Tax Adjustments	(1,208,168)
37	Federal Tax on Other Tax Adj @ 21%	47,087
38		
39	Total Federal Income Tax	$ 1,023,370

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 15 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	$ 63,835,278
2	Operations and Maintenance Expenses	39,636,280
3	Taxes Other Than Income	2,380,283
4	Regulatory Debits/Credits	219,223
5	Interest	4,019,212
6	State Income (Excise) Tax Depreciation	6,543,263
7		
8	Other Line Items to Derive Taxable Income	
9	Amortization of Limited-Term Plant	282,211
	ARO Accretion Expense	10,126
10	Income Tax Adjustments	1,498,323
11	Allowance for AFUDC	(1,432,393)
12	IERCO Taxable Income	(979,244)
13		
14		
15		
16		
17		
18		
19		
20		
21	TOTAL Utility Operating Expenses (Enter lines 4 thru 20)	
22		
13		
14	State Tax Net Income	$ 11,657,995
15		
16		
17		
18		
19	Show Computation of Tax:	
20		
21	State Taxes	256,138
22	Add: FIN 48 Adjustment	-
23	Prior Period Adjustment	(257,085)
24		
25		
26	Total Oregon State Tax	$ (947)

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		17,206	0
4	Other Operating (See Note 1)		48,346	(441,703)
5				
6	Non-Operating			
7				
8				
9	Total Electric	$	$ 65,552	$ (441,703)
10	Gas	$	$	$
11				
12				
13	Other			
14	Total Gas	$	$	$
15	Other Non-Electric	$	$	$
16	Total (Account 190)	$	$ 65,552	$ (441,703)
17	Classification of TOTALS			
18	Federal Income Tax	$	$	$
19	State Income Tax	$	$	$
20	Local Income Tax	$	$	$
	Note 1:			
	Rate Case Disallowance		4,558	(36)
	Executive Deferred Compensation		1,255	(11)
	Executive Deferred Compensation Long-Term		0	0
	SFAS 112 - Post Retirement Benefits		6,330	(56)
	Non-VEBA Pension and Benefits		11,940	(220)
	FAS 123R - Stock Based Compensation		2,519	(49,499)
	Provision for Rate Refunds		0	0
	Revenue Sharing		0	(65,981)
	Stock Based Comp - Reserve		35,329	0
	Incentive Reserve - Deferred Only		21,675	0
	Federal NOL		0	0
	Valmy Union Pacific Contract		0	0
	Deferred Idaho ITC		142,181	0
	VEBA - Post Retiree Benefits		3,727	(60,964)
	Bridger Revenue Deferral		234	(6,459)
	AFUDC Hells Canyon Relicensing		14,469	(221,126)
	Reg Liability		0	0
	Reg Asset		0	0
	Boardman Decommission		0	0
	USBR-American Falls O&M Costs Settlement		498	(4)
	Oregon Pension Expense		1,264	(16,799)
	Incentive Deferral - Profit Sharing not in rates		1,748	(10,068)
	OR Reconnect Fees Adv		0.45	(37)
	Asset Retirement Obligation (ARO)		573	(10,432)
	Deferred GBC Federal		(201,060)	0
	Retention Pay Accrual		1,104	(10)
	Total	$	$ 48,346	$ (441,703)

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					
		Debits		Credits			
Amounts Debited (Account 410.2) (e)	Amounts Credited (Account 411.2) (f)	Acct. No. (g)	Amount (h)	Acct. No. (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
$	$		$		$	$	2
							3
							4
							5
8,279	(38,746)						6
							7
							8
$ 8,279	$ (38,746)		$		$	$	9
$	$		$		$	$	10
							11
							12
							13
$	$		$		$	$	14
$ -			$		$	$	15
$ 8,279	$ (38,746)		$		$	$	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)	CHANGES DURING YEAR: Amounts Credited (Account 411.1) (d)
1	Account 282			
2	Electric		$ 218,237	$ (860,026)
3	Gas			
4	Other (Define)			
5	TOTAL (Enter Total of lines 2 thru 4)		218,237	(860,026)
6	Other (Specify)			
7	FERC Jurisdictional Deferral			
8	Non-Utility Property			
9	TOTAL Account 282 (Enter Total of lines 5 thru 8)		$ 218,237	$ (860,026)
10	Classification of TOTAL			
11	Federal Income Tax			
12	State Income Tax			
13	Local Income Tax			

Line 2:			
Depr Timing Differences		153,149	(840,813)
Intangible Asset - Labor Deductions		25,050	-
N Valmy Partnership Capitalized Items		0	-
CIAC as Taxable Income		2	(17,967)
FERC Juris-S Georgia-Acct 282 Def only		0	-
Engineering Fees		4,288	(1,247)
Software Costs		35,748	-
Total		218,237	(860,026)

ACCUMULATED DEFERRED INCOME TAXES-OTHER PROPERTY (Account 282) (Continued)
which each method is being applied and date method was adopted.
3.Beginning balance may be omitted if not readily available. Report electric utility deferred taxes only.
4. Use separate pages as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited (Account 410.2)	Amounts Credited (Account 411.2)	Acct. No.	Amount	Acct. No.	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
$ -	$ -				$ -		2
							3
							4
0	0				0		5
							6
							7
$ -	$ -						8
$ -	$ -				$ -		9
							10
							11
							12
							13

ACCUMULATED DEFERRED INCOME TAXES-OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. In the space provided below include amounts relating to insignificant items under Other.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited (Account 410.1) (c)	Amounts Credited (Account 411.1) (d)
1	Account 283			
2	Electric (See Note 1)		1,556,959	(768,354)
3				
4	Total Electric		1,556,959	(768,354)
5				
6				
7	Other (See Note 2)			
8				
9				
10	Total (Account 283) (Enter Total of lines 4 - 9)		$ 1,556,959	$ (768,354)
11	Classification of Total:			
12	Federal Income Tax			
13	State Income Tax			
14	Local Income Tax			
	Note 1:			
	Oregon PCAM		10,420	0
	Langley Revenue Accrual		21,215	(192)
	PCA		0	0
	Conservation Programs		18,031	(65,099)
	Oregon Excess Power Supply Costs		0	0
	OATT Revenue Deficiency		0	0
	Emission Allowances		0	0
	Fixed Cost Adjustment (FCA)		152,950	(3,731)
	OPUC Grid West Loans		0	0
	Intervenor Funding Orders		8	(905)
	Bonus Deferral		0	0
	Prepaid Credit Facility		17	(1,948)
	EIM Deferral		13	(10,241)
	REC Sales		26,306	(42,706)
	Pension Expense		541,250	(244,415)
	Valmy Settlement Adjust		89,679	(357,108)
	Valmy Depreciation Adjustment		681,643	(3,201)
	Custom Efficiency Incentive Payment		0	0
	LIDAR Surveys Deferral		5	(604)
	Reg Asset		0	0
	Siemens LTP Contract		675	(28)
	Siemens OR DRB Interest Reserve		8	(442)
	Boardman Decommission		14,605	(33,944)
	Boardman Removal		99	(4)
	PS&I Costs		32	(3,584)
	Royalty Income		1	(202)
	Total		1,556,959	(768,354)
	Note 2:			
	Advance Coal Royalties			
	Unrealized Gain/Loss from Rabbi Trust			
	Oregon Non-Operating Property Tax Adj			
	Unrealized Gain/Loss from SMSP			
	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.
		Debits		Credits			
Amounts Debited (Account 410.2) (e)	Amounts Credited (Account 411.2) (f)	Acct. No. (g)	Amount (h)	Acct. No. (i)	Amount (j)	(k)	
							1
0	0						2
							3
-	-		-		-		4
							5
							6
9	(579)						7
							8
							9
$ 9	$ (579)		$ -		$ -		10
							11
							12
							13
							14

0	0
0	0
2	(233)
0	(0)
7	(345)
9	(579)

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	$ 345,994	411.4	$ (121,607)			
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).......	$ 538,267,881	$ 538,267,881				
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).......	$ 538,267,881	$ 538,267,881				
9	Leased to Others.......						
10	Held for Future Use.......	$ 89,977	$ 89,977				
11	Construction Work in Progress.......	$ 45,633,095	$ 45,633,095				
12	Acquisition Adjustments.......	100,845	$ 100,845				
13	TOTAL Utility Plant (Enter Total of lines 8 thru 12)...	$ 584,091,798	$ 584,091,798				
14	Accum. Prov. for Depr., Amort., & Depl.......	**NOT AVAILABLE**					
15	Net Utility Plant (Enter Total of line 13 less 14).......	$ 584,091,798	$ 584,091,798				
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION						
17	In Service						
18	Depreciation.......						
19	Amort. and Depl. of Producing Natural Gas Land and Land Rights.......						
20	Amort. of Underground Storage Land and Land Righ						
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 an						
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 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..........	12,607,486	18,562				12,626,048	(311)	9
10	(312) Boiler Plant Equipment..........	43,783,079	78,108				43,861,187	(312)	10
11	(313) Engines and Engine Driven Generators..........	0					-	(313)	11
12	(314) Turbogenerator Units..........	13,569,621					13,569,621	(314)	12
13	(315) Accessory Electric Equipment..........	4,637,686	12,914				4,650,600	(315)	13
14	(316) Misc. Power Plant Equipment..........	1,820,386	155,624				1,976,010	(316)	14
15	(317) Asset Retirement Costs for Steam Production	5,046,008					5,046,008	(317)	15
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)..........	81,570,875	265,208	0	0	0	81,836,084		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..........	11,191,728	128,562				11,320,290	(330)	27
28	(331) Structures and Improvements..........	25,977,341	2,857,426	(71,542)			28,763,226	(331)	28
29	(332) Reservoirs, Dams, and Waterways..........	92,100,125	195,546				92,295,672	(332)	29
30	(333) Water Wheels, Turbines, and Generators..........	24,428,194	2,577,691				27,005,885	(333)	30
31	(334) Accessory Electric Equipment..........	12,472,792	277,500				12,750,291	(334)	31
32	(335) Misc. Power Plant Equipment..........	5,770,290	432,845	(110,944)			6,092,191	(335)	32
33	(336) Roads, Railroads, and Bridges..........	1,388,105	940,325				2,328,429	(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)..........	173,328,576	7,409,894	(182,487)		0	180,555,983		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)......	254,899,451	7,675,103	(182,487)	0	0	262,392,067		46
47	3. TRANSMISSION PLANT								47
48	(350) Land and Land Rights......	4,841,964	$ 35,573	(5)			4,877,532	(350)	48
49	(352) Structures and Improvements......	7,397,310	65,779	(2,855)			7,460,234	(352)	49
50	(353) Station Equipment......	42,137,308	7,073,163	(1,051,826)			48,158,644	(353)	50
51	(354) Towers and Fixtures......	26,659,106	453,285	(2,746)			27,109,646	(354)	51
52	(355) Poles and Fixtures......	34,768,831	1,212,202	(259,365)			35,721,668	(355)	52
53	(356) Overhead Conductors and Devices......	29,317,762	702,662	(167,579)			29,852,845	(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)......	145,170,848	9,542,664	(1,484,376)	0	0	153,229,136		58
59	4. DISTRIBUTION PLANT								59
60	(360) Land and Land Rights......	195,702	$ 453				196,155	(360)	60
61	(361) Structures and Improvements......	1,720,583	(59,041)	(10,143)			1,651,398	(361)	61
62	(362) Station Equipment......	10,538,885	562,623	(7,095)			11,094,413	(362)	62
63	(363) Storage Battery Equipment......	0	0				0	(363)	63
64	(364) Poles, Towers, and Fixtures......	20,768,495	392,897	(123,475)			21,037,917	(364)	64
65	(365) Overhead Conductors and Devices......	9,201,274	250,638	(113,854)			9,338,059	(365)	65
66	(366) Underground Conduit......	705,125	35,078	(9,273)			730,930	(366)	66
67	(367) Underground Conductors and Devices......	3,697,195	235,206	(22,990)			3,909,411	(367)	67
68	(368) Line Transformers......	50,348,773	2,416,498	(146,273)			52,618,998	(368)	68
69	(369) Services......	2,889,586	7,139	(40,119)			2,856,606	(369)	69
70	(370) Meters......	8,093,181	393,156	(128,859)			8,357,478	(370)	70
71	(371) Installations on Customer Premises......	229,714	8,705	(3,426)			234,993	(371)	71
72	(372) Leased Property on Customer Premises......	0					0	(372)	72
73	(373) Street Lighting and Signal Systems......	210,991	2,420	(2,367)			211,044	(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)......	108,599,503	4,245,772	(607,874)	0	0	112,237,401		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	528,331	17,224	(1,134)			544,421	(390)	78
79	(391) Office Furniture and Equipment	135,332	(49,596)	(85,736)			0	(391)	79
80	(392) Transportation Equipment	3,172,130	191,766	(75,103)			3,288,793	(392)	80
81	(393) Stores Equipment	0					0	(393)	81
82	(394) Tools, Shop and Garage Equipment	4,129	(4,129)				0	(394)	82
83	(395) Laboratory Equipment	53,332	(29,370)				23,962	(395)	83
84	(396) Power Operated Equipment	2,098,362	122,986	(22,027)			2,199,321	(396)	84
85	(397) Communication Equipment	4,400,666	79,042	(382,568)			4,097,140	(397)	85
86	(398) Miscellaneous Equipment	5,144					5,144	(398)	86
87	SUBTOTAL (Enter Total of lines 77 thru 86)	10,405,669	327,923	(566,568)	0	0	10,167,024		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)	10,405,669	327,923	(566,568)	0	0	10,167,024		91
92	TOTAL (Accounts 101 and 106)	519,317,723	21,791,461	(2,841,304)	0	0	538,267,881		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	519,317,723	21,791,461	(2,841,304)	-	-	538,267,881		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 thr				
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)........	$ 253,340,634	$ 253,340,634				
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)........	253,340,634	253,340,634				
9	Leased to Others........						
10	Held for Future Use........	$ 173,882	173,882				
11	Construction Work in Progress........						
12	Acquisition Adjustments........						
13	TOTAL Utility Plant (Enter Total of lines 8 thru 12)........	253,514,515	253,514,515				
14	Accum. Prov. for Depr., Amort., & Depl........	$ 101,625,947	101,625,947				
15	Net Utility Plant (Enter Total of line 13 less 14)........	$ 151,888,568	$ 151,888,568				
16	DETAIL OF ACCUMULATED PROVISIONS FOR DEPRECIATION, AMORTIZATION AND DEPLETION						
17	In Service						
18	Depreciation........	$ 100,585,292	$ 100,585,292				
19	Rights……………………..		0				
20	Amort. of Underground Storage Land and Land Rights........						
21	Amort. of Other Utility Plant........	$ 1,040,655	1,040,655				
22	TOTAL In Service (Enter total of lines 18 thru 21)........	101,625,947	101,625,947				
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).....	$ 101,625,947	$ 101,625,947				

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..........	$ 246					$ 237	(301)	2
3	(302) Franchises and Consents..........	1,306,168					1,373,953	(302)	3
4	(303) Miscellaneous Intangible Plant..........	1,146,257					1,205,083	(303)	4
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)..........	$ 2,452,671					$ 2,579,272		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)....	$ 50,152,765					$ 48,837,938		16
17	B. Nuclear Production Plant								17
18	(320) Land and Land Rights..........							(320)	18
19	(321) Structures and Improvements..........							(321)	19
20	(322) Reactor Plant Equipment..........							(322)	20
21	(323) Turbogenerator Units..........							(323)	21
22	(324) Accessory Electric Equipment..........							(324)	22
23	(325) Misc. Power Plant Equipment..........							(325)	23
24	(326) Asset Retirement Costs for Nuclear Production..........							(326)	
25	TOTAL Nuclear Production Plant (Enter Total of lines 17 thru 24)								25
26	C. Hydraulic Production Plant								26
27	(330) Land and Land Rights..........							(330)	27
28	(331) Structures and Improvements..........							(331)	28
29	(332) Reservoirs, Dams, and Waterways..........							(332)	29
30	(333) Water Wheels, Turbines, and Generators..........							(333)	30

ELECTRIC PLANT IN SERVICE

(In addition to Account 101, Electric Plant in Service [Classified], this schedule includes Account 102, Electric Plant Purchased or Sold, Account 103, Experimental Electric Plant Unclassified and Account 106, Completed Construction Not Classified-Electric.)

1. Report below the original cost of electric plant in service according to prescribed accounts.

2. Do not include as adjustments, corrections of additions and retirements for the current or the preceding year. Such items should be included in column (c) or (c) as appropriate.

ELECTRIC PLANT IN SERVICE (Continued)

3. Credit adjustments of plant accounts should be enclosed in parentheses to indicate the negative effect of such amounts.

4. Reclassifications or transfers within utility plant accounts should be shown in column (f). Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, Electric Plant Purchased or Sold. In showing the clearance of Account 102, include in column (c) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
31	(334) Accessory Electric Equipment							(334)	31
32	(335) Misc. Power Plant Equipment							(335)	32
33	(336) Roads, Railroads, and Bridges							(336)	33
34	(337) Asset Retirement Costs for Hydraulic Production							(326)	34
35	TOTAL Hydraulic Production Plant (Enter Total of lines 26 thru 34)	$ 36,665,640					$ 36,918,319		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)	$ 23,231,768					$ 22,527,567		45
46	TOTAL Production Plant (Enter Total of lines 16, 25, 35, and 45)	110,050,173					108,283,824		46
47	3. TRANSMISSION PLANT								47
48	(350) Land and Land Rights	1,581,193					1,596,484	(350)	48
49	(352) Structures and Improvements	3,418,917					3,323,896	(352)	49
50	(353) Station Equipment	18,299,957					18,120,988	(353)	50
51	(354) Towers and Fixtures	8,796,719					8,669,034	(354)	51
52	(355) Poles and Fixtures	7,840,346					8,039,075	(355)	52
53	(356) Overhead Conductors and Devices	9,675,574					9,587,616	(356)	53
54	(357) Underground Conduit							(357)	54
55	(358) Underground Conductors and Devices							(358)	55
56	(359) Roads and Trails	16,621					16,007	(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)	$ 49,629,327					$ 49,353,100		58
59	4. DISTRIBUTION PLANT								59
60	(360) Land and Land Rights	171,440					171,256	(360)	60
61	(361) Structures and Improvements	1,807,901					1,734,201	(361)	61
62	(362) Station Equipment	10,029,500					10,573,321	(362)	62
63	(363) Storage Battery Equipment	0					0	(363)	63
64	(364) Poles, Towers, and Fixtures	20,768,495					21,037,917	(364)	64
65	(365) Overhead Conductors and Devices	9,201,274					9,338,058	(365)	65
66	(366) Underground Conduit	705,125					730,930	(366)	66
67	(367) Underground Conductors and Devices	3,697,195					3,909,411	(367)	67
68	(368) Line Transformers	22,558,234					22,276,657	(368)	68
69	(369) Services	2,889,586					2,856,606	(369)	69
70	(370) Meters	3,068,036					3,148,688	(370)	70
71	(371) Installations on Customer Premises	229,714					234,993	(371)	71

ELECTRIC PLANT IN SERVICE

(In addition to Account 101, Electric Plant in Service [Classified], this schedule includes Account 102, Electric Plant Purchased or Sold, Account 103, Experimental Electric Plant Unclassified and Account 106, Completed Construction Not Classified-Electric.)

1. Report below the original cost of electric plant in service according to prescribed accounts.

2. Do not include as adjustments, corrections of additions and retirements for the current or the preceding year. Such items should be included in column (c) or (c) as appropriate.

ELECTRIC PLANT IN SERVICE (Continued)

3. Credit adjustments of plant accounts should be enclosed in parentheses to indicate the negative effect of such amounts.

4. Reclassifications or transfers within utility plant accounts should be shown in column (f). Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, Electric Plant Purchased or Sold. In showing the clearance of Account 102, include in column (c) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

Line No.	Account (a)	Balance at Beginning of Year (b)	Additions (c)	Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
72	(372) Leased Property on Customer Premises..................................							(372)	72
73	(373) Street Lighting and Signal Systems...	210,991					211,044	(373)	73
74	(374) Asset Retirement Costs for Distribution Plant...........................							(374)	74
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)...............	$ 75,337,491					$ 76,223,082		75
76	5. GENERAL PLANT								76
77	(389) Land and Land Rights...	751,976					736,606	(389)	77
78	(390) Structures and Improvements...	5,195,958					5,293,817	(390)	78
79	(391) Office Furniture and Equipment..	1,934,154					2,013,699	(391)	79
80	(392) Transportation Equipment...	3,796,124					3,855,228	(392)	80
81	(393) Stores Equipment...	126,940					125,501	(393)	81
82	(394) Tools, Shop, and Garage Equipment..	449,519					460,592	(394)	82
83	(395) Laboratory Equipment..	597,270					568,889	(395)	83
84	(396) Power Operated Equipment..	700,463					798,494	(396)	84
85	(397) Communication Equipment...	2,331,351					2,155,794	(397)	85
86	(398) Miscellaneous Equipment..	300,554					306,232	(398)	86
87	SUBTOTAL (Enter Total of lines 77 thru 86)..................................	16,184,308					16,314,854		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)............	16,184,308					16,314,854		90
91	TOTAL (Accounts 101 and 106)...	253,653,970					252,754,132		91
92	(102) Electric Plant Purchased **..								92
93	(Less) (102) Electric Plant Sold **..								93
94	Asset Retirement Obligations (ARO)..	640,209					586,502		94
95	TOTAL Electric Plant in Service...	$ 254,294,179					$ 253,340,634		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	6,543,263	6,543,263		
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)	6,543,263	6,543,263		
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)	$ 6,543,263	$ 6,543,263		

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	$ 27,546,122	$ 27,546,122		
19	Nuclear Production				
20	Hydraulic Production - Conventional	17,834,448	17,834,448		
21	Hydraulic Production - Pumped Storage				
22	Other Production	4,636,807	4,636,807		
23	Transmission	15,463,339	15,463,339		
24	Distribution	29,620,811	29,620,811		
25	General	4,834,892	4,834,892		
26	FAS 143 Adj &/or Disallowed Cost	648,874	648,874		
27	TOTAL (Enter Total of lines 18 thru 26)	$ 100,585,292	$ 100,585,292		

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)	$ 2,629,057	$ 2,222,004	
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)	764,317	727,368	
8	Transmission Plant (Estimated)	427,157	387,177	
9	Distribution Plant (Estimated)	1,082,032	1,155,187	
10	Assigned to - Other	57,637	(31,682)	
11	TOTAL Account 154 (Enter Total of lines 5 thru 10)	2,331,142	2,238,048	
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)	81,315	59,513	
16				
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	$ 5,041,515	$ 4,519,565	

ELECTRIC ENERGY ACCOUNT

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

Line No.	Item (a)	Megawatt Hours (b)	Line No.	Item (a)	Megawatt Hours (b)
1	SOURCES OF ENERGY		20	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		21	Sales to Ultimate Consumers (Including Interdepartmental Sales)	
3	Steam.......... Steam.................................				
4	Nuclear...		22	Sales for Resale	
5	Hydro-Conventional....................................		23	Energy Furnished Without Charge	
6	Hydro-Pumped Storage.............................	**INFORMATION**	24	Energy Used by the Company (Excluding Station Use):	**INFORMATION**
7	Other..				
8	Less Energy for Pumping.........................	**NOT**	25	Electric Department Only	**NOT**
9	Net Generation (Enter Total of lines 3 thru 8)....................................	**AVAILABLE**	26	Energy Losses:	**AVAILABLE**
10	Purchases..		27	Transmission and Conversion Losses	
11	Interchanges:		28	Distribution Losses	
12	In (gross)..		29	Unaccounted for Losses	
13	Out (gross)...		30	TOTAL Energy Losses	
14	Net Interchanges (Lines 12 & 13).............		31	Energy Losses as Percent of Total on Line 19	
15	Transmission for/by Others (Wheeling)				
16	Received (MWH)		32	TOTAL (Enter Total of lines 21, 22, 23, 25, and 30)	
17	Delivered (MWh)				
18	Net Transmission (lines 16 & 17).............				
19	TOTAL (Enter Total of lines 9, 10, 14, and 18).........................				

MONTHLY PEAKS AND OUTPUT

1. Report below the information called for pertaining to simultaneous peaks established monthly (in megawatts) and monthly output (in megawatt-hours) for the combined sources of electric energy of respondent.
2. Report in column (b) the respondent's maximum MW load as measured by the sum of its coincidental net generation and purchases plus or minus net interchange, minus temporary deliveries (not interchange) Show monthly peak including such emergency deliveries of emergency power to another system. in a footnote and briefly explain the nature of the emergency. There may be cases of commingling of purchases and exchanges and "wheeling," also of direct deliveries by the supplier to customers of the reporting utility wherein segregation of MW demand for determination of peaks as specified by this report may be unavailable. In these cases, report peaks which include these intermingled transactions. Furnish an explanatory note which indicates, among other things, the relative significance of the deviation from basis otherwise applicable. If the individual MW amounts of such totals are needed for billing under separate rate schedules and are estimated, give the amount and basis of estimate.
3. State type of monthly peak reading (instantaneous 15, 30, or 60 minutes integrated).
4. Monthly output is the sum of respondent's net generation for load and purchases plus or minus net interchange and plus or minus net transmission or wheeling. Total for the year must agree with line 19 above.
5. If the respondent has two or more power systems not physically connected, furnish the information called for below for each system.

NAME OF SYSTEM: OREGON RETAIL ONLY

Line No.	Month (a)	MONTHLY PEAK Megawatts (b)	Day of Week (c)	Day of Month (d)	Hour (e)	Type of Reading (f)	Monthly Output (MWh) (See Instr. 4) (g)
33	January	109.05	Thursday	4	9 A.M	60 Min. Int	64,209
34	February	101.20	Tuesday	20	8 A.M.	" " "	52,660
35	March	87.66	Tuesday	6	8 A.M.	" " "	54,825
36	April	71.87	Friday	27	6 P.M.	" " "	51,677
37	May	93.25	Tuesday	29	8 P.M.	" " "	61,849
38	June	106.59	Monday	25	7 P.M.	" " "	62,744
39	July	118.27	Monday	9	7 P.M.	" " "	78,340
40	August	130.86	Friday	10	6 P.M.	" " "	73,395
41	September	106.82	Thursday	6	6 P.M.	" " "	53,217
42	October	90.85	Monday	15	9 A.M.	" " "	55,104
43	November	99.51	Tuesday	13	8 A.M.	" " "	58,940
44	December	113.93	Thursday	6	8 A.M.	" " "	68,465
45	TOTAL	1,229.86					735,425

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	$ 543,835	$ 25,565	$ 518,270
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	1,702,311	80,023	1,622,288
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	74,325	3,494	70,831
10	of items so grouped is shown)			
11				
12				
13	Directors' fees and expenses (see detail on page 39)	938,198	44,103	894,095
14				
15	Memberships and contributions (see detail on page 39)	346,484	16,288	330,196
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**	$ 3,605,153	$ 169,472	$ 3,435,681

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	Anette Elg-Fees and expenses	$ 86,130	4,049	82,081
4	Christine King-Fees and expenses	93,060	4,375	88,685
5	Richard Navarro - Fees and expenses	86,130	4,049	82,081
6	Dennis Johnson - Fees and expenses	82,170	3,863	78,307
7	J LaMont Keen - Fees and expenses	30,938	1,454	29,484
8	Judith Johansen-Fees and expenses	86,130	4,049	82,081
9	Richard Dahl - Fees	103,455	4,863	98,592
10	Robert A Tinstman Fees and expenses	187,110	8,796	178,314
11	Ronald Jibson - Fees and expenses	80,190	3,770	76,420
12	Thomas Carlile - Fees and expenses	84,150	3,956	80,194
13	Director Travel and Lodging	18,735	881	17,854
14	SUBTOTAL	938,198	44,103	894,093
15				
16	Other Expenses >$5,000:			
17	Bank of New York	$ 7,450	350	7,100
18	Investis, Inc.	7,325	344	6,981
19	Retirement Related Expense	10,000	470	9,530
20	Port of Morrow	5,475	257	5,218
21	Miscellaneious <$5,000	44,075	2,072	42,003
22	SUBTOTAL	74,325	3,494	70,831
23	Miscellaneous General Management Expenses:			
24	American Stock Transfers & Trust	71,602	3,366	68,236
25	Bloomberg Finance LP	24,506	1,152	23,354
26	Broadridge Financial Solutions	49,767	2,339	47,428
27	Deutsche Bank Trust Co.	30,000	1,410	28,590
28	EQ Shareholder Services	87,671	4,121	83,550
29	NASDAQ Corporate Solutions LLC	52,947	2,489	50,458
30	New York Stock Exchange I	64,025	3,010	61,015
31	OKAPI Partners, LLC	19,800	931	18,869
32	Payroll Related Expenses	177,463	8,342	169,121
33	PR Newswire	17,288	813	16,475
34	Rivel Research Group	15,840	745	15,095
35	Stock Based Compensation	1,039,102	48,846	990,256
36	Union Bank, N.A.	9,680	455	9,225
37	Travel Expense-Stock Related	15,868	746	15,122
38	Wells Fargo Shareowner Services	26,752	1,258	25,494
39	SUBTOTAL	1,702,311	80,023	1,622,288
40				
41	Memberships and Contributions:			
42	Arizona State University	50,000	2,350	47,650
43	Associated Taxpayers of Idaho - Membership	22,000	1,034	20,966
44	Bannock Development Corp	8,500	400	8,100
45	CEATI International, Inc.	15,250	717	14,533
46	Chambers of Commerce	46,041	2,164	43,877
47	ESource	31,624	1,487	30,137
48	Idaho Association of Commerce and Industry	15,500	729	14,771
49	National Association of Directors	8,075	380	7,695
50	National Hydropower Association	38,201	1,796	36,405
51	North American Energy Standard	7,000	329	6,671
52	Pacific NW Utilities	52,093	2,449	49,644
53	Southern Idaho Economic Development	5,000	235	4,765
54	Sun Valley Economic Development	5,500	259	5,241
55	Misc Memberships under $5,000	41,700	1,960	39,740
56	SUBTOTAL	346,484	16,288	330,196
57				
58				
59	**TOTAL**	$ 3,061,318	$ 140,413	$ 2,920,905

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	$ 860,000	$ 40,427
3				
4	Senior Vice President, CFO and Treasurer …...........................	Steven R. Keen	445,000	$ 20,919
5				
6	Senior Vice President, COO..	Lisa Grow	445,000	$ 20,919
7				
8	Senior Vice President, Public Affairs...	Jeffrey Malmen	305,000	14,338
9				
10	Senior Vice President, Admin Services & Chief HR Officer……..	Lonnie Krawl (1)	187,000	8,791
11				
12	Senior Vice President & General Counsel	Brian Buckham	340,000	15,983
13				
14	Vice President, T&D Engineering & Contstruction, and CSO......	Vern Porter	305,000	14,338
15				
16	Vice President of Power Supply..	Tessia Park	285,000	13,397
17				
18	Vice President, Customer Operations & Bus. Development.........	Adam Richins	260,000	12,222
19				
20	Vice President, Corporate Controller & CAO...............................	Ken Petersen	265,000	12,457
21				
22	Vice President Information Technology & CIO............................	Jeff Glenn	262,000	12,316
23				
24	Vice President of Rgulatory Affairs..	Tim Tatum	200,000	9,402
25				
26	Corporate Secretary..	Patrick Harrington	210,000	9,872
27				
28				
29	(1) Retirement effective 8/31/18, Salary shows YTD wages			
30				
31				
32				
33				
34				
35				
36				
37				

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	250
ADA COUNTY LINCOLN DAY ASSOCIA	"	5,000
ALAN OLSEN FOR STATE SENATE	"	500
ARNIE ROBLAN FOR STATE SENATE	"	500
BERT BRACKETT FOR STATE SENATO	"	1,000
BRAD LITTLE FOR GOVERNOR	"	5,000
BRAD WITT FOR STATE REPRESENTA	"	500
BRANDON WOOLF FOR STATE CONTRO	"	500
BRENT CRANE FOR STATE REPRESEN	"	1,000
BRENT HILL FOR STATE SENATE	"	1,000
BRITT RAYBOULD FOR STATE REPRE	"	500
BROOKE GREEN FOR STATE REPRESE	"	500
C SCOTT GROW FOR STATE SENATE	"	500
CANYON COUNTY REPUBLICANS	"	500
CARL CRABTREE FOR STATE SENATE	"	250
CAROLINE TROY FOR STATE REPRES	"	750
CHAMBER OF COMMERCE LEWIS CLAR	"	1,500
CHAMBER OF COMMERCE, BOIS	"	920
CHERI HELT FOR STATE REPRESENT	"	1,500
CHERIE BUCKNER-WEBB FOR STATE	"	1,000
CHUCK WINDER FOR STATE SENATE	"	1,000
CLARK KAUFFMAN FOR STATE REPRE	"	500
CLIFF BAYER FOR STATE SENATOR	"	750
COMMITTEE TO ELECT DANIEL BONH	"	500
COMMITTEE TO ELECT JOHN LIVELY	"	250
COMMITTEE TO ELECT MIKE MCLANE	"	1,000
COMMITTEE TO ELECT PAM MARSH	"	500
COMMITTEE TO RE-ELECT GREG SMI	"	1,000
DAN JOHNSON FOR STATE SENATE	"	1,000
DAVE BIETER FOR MAYOR	"	1,000
DAVE LENT FOR STATE SENATE	"	500
DON CHEATHAM FOR STATE SENATE	"	750
DOUG OKUNIEWICZ FOR STATE REPR	"	250
DOUG RICKS FOR STATE REPRESENT	"	250
DUSTIN MANWARING FOR STATE REP	"	500
ELAINE SMITH FOR STATE	"	250
ENERGY POLICY INSTITUTE	"	2,000
FRED MARTIN FOR STATE SENATE	"	1,000

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
FRED WOOD FOR STATE REPRESENTA	426.400	1,000
FRIENDS OF BILL HANSELL	"	500
FRIENDS OF DAVID BROCK SMITH	"	500
FRIENDS OF GINNY BURDICK	"	1,000
FRIENDS OF HERMAN BAERTSCHIGER	"	500
FRIENDS OF JACKIE WINTERS	"	1,000
FRIENDS OF JENNIFER WILLIAMSON	"	1,000
FRIENDS OF KARIN POWER	"	1,000
FRIENDS OF LEE BEYER	"	750
FRIENDS OF MICHAEL DEMBROW	"	1,000
FRIENDS OF TINA KOTEK	"	1,000
GARY COLLINS FOR STATE	"	1,000
GARY MARSHALL FOR STATE REPRES	"	250
GAYANN DEMORDAUNT FOR STATE RE	"	250
GRANT BURGOYNE FOR STATE SENAT	"	500
GREG BARRETO FOR HD 58	"	500
GREG CHANEY FOR STATE REPRESEN	"	250
HOUSE REPUBLICAN CAUCUS	"	2,000
IDAHO DEMOCRATIC LEGISLATIVE C	"	1,000
IDAHO ENVIRONMENTAL FORUM	"	1,000
IDAHO FEDERATION OF REPUBLICAN	"	250
IDAHO MINING ASSOCIATION	"	300
IDAHO PROSPERITY FUND	"	35,500
IDAHO REALTORS	"	1,500
IDAHO SENATE REPUBLICANS	"	1,000
IDAHO STATE SOCIETY	"	12,136
IDAHO VICTORY FUND PAC	"	5,000
IDAHO WATER USERS ASSOCIA	"	3,200
JANICE MCGEACHIN FOR LT GOVERN	"	1,000
JAROM WAGONER FOR STATE REPRES	"	500
JASON MONKS FOR STATE REPRESEN	"	500
JEFF AGENBROAD FOR STATE SENAT	"	250
JEFF THOMPSON FOR STATE REPRES	"	(250)
JERALD RAYMOND FOR STATE REPRE	"	500
JIM ADDIS FOR STATE REPRESENTA	"	1,250
JIM GUTHRIE FOR STATE SENATE	"	1,000
JIM PATRICK FOT STATE SENATE	"	750
JIM RICE FOR STATE SENATE	"	500

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
JIM WOODWARD FOR STATE SENATE	426.400	1,000
JOE PALMER FOR STATE REPRESENT	"	500
JOHN GANNON FOR STATE REPRESEN	"	500
JOHN MCCROSTIE FOR STATE REPRE	"	250
JUDY BOYLE FOR STATE REPRESENT	"	250
JULIE VAN ORDEN FOR STATE REPR	"	500
KATE BROWN FOR GOVERNOR	"	10,000
KATHLEEN TAYLOR FOR OREGON	"	500
KELLY ANTHON FOR STATE SENATE	"	1,500
KEN HELM FOR HD 34	"	1,000
KEVIN ANDRUS FOR STATE REPRESE	"	250
KIRK ADAMS FOR STATE REPRESENT	"	250
LAURIE LICKLEY FOR STATE REPRE	"	500
LAWERENCE DENNEY FOR IDAHO	"	2,500
LEE HEIDER FOR STATE SENATE	"	1,000
LINDA WRIGHT HARTGEN FOR STATE	"	500
LYNN FINDLEY FOR STATE REPRESE	"	500
MARC GIBBS FOR STATE REPRESENT	"	250
MARK HARRIS FOR STATE SENATE	"	750
MARK NYE FOR STATE SENATE	"	250
MARY SOUZA FOR STATE SENATE	"	1,000
MARYANNE JORDAN FOR STATE SENA	"	1,000
MAT ERPELDING FOR STATE REPRES	"	1,000
MEGAN BLANKSMA FOR STATE REPRE	"	250
MICHELLE STENNETT FOR STATE SE	"	1,000
MIKE MOYLE FOR STATE REPRESENT	"	1,500
NEW HORIZONS PAC	"	1,000
NEXT GEN LEADERSHIP	"	1,000
OSCAR EVANS FOR STATE REPRESEN	"	250
OTTER TRIBUTE DINNER	"	2,500
PAT MCDONALD FOR STATE REPRESE	"	250
PATTI ANNE LODGE FOR	"	1,000
PAUL AMADOR FOR STATE REPRESEN	"	1,000
PAUL SHEPHERD FOR STATE REPRES	"	250
PETER COURTNEY FOR STATE SENAT	"	1,000
PUGET SOUND ENERGY FEDERAL GOV	"	474
RANDY ARMSTRONG FOR STATE REPR	"	250
RE-ELECT LARRY GIVENS	"	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
RICK YOUNGBLOOD FOR STATE REPR	426.400	500
ROB MASON FOR STATE REPRESENTA	"	500
ROBERT ANDERST FOR STATE REPRE	"	500
ROD FURNISS FOR STATE REPRESEN	"	500
RYAN KERBY FOR STATE REPRESENT	"	750
SAGE DIXON FOR STATE REPRESENT	"	250
SALLY TOONE FOR STATE REPRESEN	"	250
SCOTT BEDKE FOR STATE REPRESEN	"	1,500
SCOTT SYME FOR STATE REPRESENT	"	250
SENATE REPUBLICAN CAUCUS	"	1,000
SOUTH DAKOTA ELECTRIC UTILITY	"	350
SQ ACHD SOCIAL COM	"	1,000
STEVE VICK FOR STATE SENATOR	"	1,500
STEVEN HARRIS FOR STATE REPRES	"	250
TERRY GESTRIN FOR STATE REPRES	"	500
THOMAS LOERTSCHER FOR STATE	"	500
TODD LAKEY FOR STATE SENATE	"	750
TOM DAYLEY FOR STATE REPRESENT	"	500
VAN BURTENSHAW FOR STATE REPRE	"	500
VAN BURTENSHAW FOR STATE SENAT	"	250
VITO BARBIERI FOR STATE REPRES	"	250
WENDY HORMAN FOR STATE REPRESE	"	500
WERNER RESCHKE FOR OREGON	"	500
Total Political Contributions		**$ 168,380**

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	74,453	None
IDACORP EMPLOYEES	"	145,547	"
TOTAL MATCHING EMPLOYEE COMMUNITY SERVICE FUND	**426101**	**220,000**	
AMERICAN HEART ASSOCIATION	426101	7,500	None
AMERICAN RED CROSS OF GREATER	"	1,000	"
BOYS AND GIRLS CLUB	"	1,600	"
CAMP RAINBOW GOLD	"	2,500	"
CANYON COUNTY FESTIVAL	"	3,921	"
CHILDREN'S HOME SOCIETY OF ID	"	1,250	"
FAMILY ADVOCATE PROGRAM	"	1,000	"
FESTIVAL OF TREES	"	1,075	"
GIRL SCOUTS OF SILVER SAGE COU	"	1,500	"
IDAHO RONALD MCDONALD HOUSE	"	2,500	"
INTERFAITH SANCTUARY HOMELESS	"	1,600	"
METRO MEALS ON WHEELS	"	1,000	"
SHRINER HOSPITALS FOR CHILDREN	"	1,000	"
ST ALPHONSUS FESTIVAL OF TREES	"	5,000	"
ST LUKES HEALTH FOUNDATION	"	7,500	"
WESTERN IDAHO TRAINING CO, INC	"	1,000	"
ZBOROWSKI, DE	"	2,500	"
Misc Health & Human Services - 31 Organizations <$1,000	"	9,123	"
TOTAL HEALTH & HUMAN SERVICES	**426102**	**52,569**	
ADAMS COUNTY FAIRBOARD	426103	1,000	None
BIG BROTHERS BIG SISTERS	"	1,250	"
BINGHAM COUNTY SENIOR CITIZENS	"	1,000	"
BIRDS OF PREY NCA PARTNERSHIP	"	5,000	"
BLAINE COUNTY CLERK	"	2,500	"
BOGUS BASIN RECREATIONAL ASSOC	"	20,000	"
BOISE MUSIC WEEK	"	1,000	"
BOISE PHILHARMONIC ASSOCIATION	"	2,500	"

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Description	Account Number	Total Amount	Amount Assigned to Oregon
BOYS & GIRLS CLUB OF ADA CO	426103	2,500	None
CHAMBER OF COMMERCE	"	14,252	"
CITY OF CAREY	"	1,750	"
COMMUNITY COUNCIL OF IDAHO	"	1,000	"
COMMUNITY FORESTRY TRUST ACCOU	"	7,000	"
FRESHWATER TRUST, THE	"	2,500	"
FRIENDS OF THE PINE VALLEY FAI	"	1,500	"
FRIENDS OF THE PORTIA CLUB INC	"	1,500	"
FRIENDS OF ZOO BOISE	"	1,500	"
FUNDSY	"	5,000	"
GARDEN CITY LIBRARY FOUNDATION	"	1,500	"
GOODING VOLUNTEER GROUP	"	1,000	"
HIGHER GROUND SUN VALLEY INC	"	1,500	"
HOME PARTNERSHIP FOUNDATION	"	2,500	"
HORSESHOE BEND CITY	"	1,300	"
ID ASSOC OF COUNTIES	"	2,500	"
IDAHO BOTANICAL GARDEN	"	3,000	"
IDAHO COMMUNITY FOUNDATION	"	6,500	"
IDAHO FOODBANK	"	2,750	"
IDAHO HUMANE SOCIETY	"	3,000	"
IDAHO LAW FOUNDATION INC	"	2,500	"
IDAHO NCF ENVIROTHON	"	2,500	"
IDAHO NONPROFIT CENTER	"	2,500	"
IDAHO PATRIOT THUNDER RIDE	"	1,000	"
IDAHO SALMON AND STEELHEAD DAY	"	2,500	"
IDAHO STATE UNIVERSITY	"	2,500	"
IDAHO WOMEN LAWYERS	"	2,500	"
LAND TRUST OF THE TREASURE VAL	"	1,000	"
LUPO,MARK J	"	4,098	"
MALMEN,JEFFREY L	"	2,000	"

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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
MCPAWS REGIONAL ANIMAL SHELTER	426103	1,500	None
NEIGHBORWORKS	"	4,000	"
OXBOW FACILITIES USAGE	"	1,050	"
PEREGRINE FUND INC, THE	"	5,000	"
PORTNEUF GREENWAY FOUNDATION	"	1,000	"
PORTNEUF VALLEY PAINTFEST	"	1,000	"
ROTARY CLUB	"	1,000	"
ROTARY DISTRICT 5400	"	1,000	"
SAWTOOTH NATIONAL FOREST AVALA	"	1,000	"
SILVER WINGS OF IDAHO	"	5,000	"
SMART WOMEN, SMART MONEY INC	"	5,000	"
SOUTHERN IDAHO RURAL DEVELOPME	"	1,000	"
SPAY NEUTER IDAHO PETS INC	"	1,000	"
STUTZMAN,SHARON E	"	1,324	"
TREASURE VALLEY NAACP	"	1,500	"
WASSMUTH CENTER FOR HUMAN RIGH	"	3,750	"
WEWERS,BRYAN J	"	1,097	"
WOMEN'S & CHILDREN'S ALLIANCE	"	5,000	"
WYAKIN WARRIOR FOUNDATION	"	3,500	"
Misc Civic and Community Serivices - 164 Organizations < $1,000	"	47,800	"
TOTAL CIVIC & COMMUNITY	**426103**	**213,921**	
BALLET IDAHO	426104	1,500	"
BOISE ART MUSEUM	"	3,000	"
BOISE CHORDSMEN	"	1,000	"
IDAHO SHAKESPEARE FESTIVAL	"	3,500	"
LIFE'S KITCHEN	"	1,500	"
LOG CABIN LITERARY CENTER	"	2,000	"
MAGIC VALLEY ARTS COUNCIL	"	2,875	"
MERIDIAN SYMPHONY ORCHESTRA	"	1,500	"
NATIONAL FEDERATION OF THE BLI	"	1,000	"

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Description	Account Number	Total Amount	Amount Assigned to Oregon
Misc Culture and Arts - 16 Organizations <$1,000	426104	5,225	"
TOTAL CULTURE & ARTS	**426104**	**23,100**	
IDAHO PUBLIC TELEVISION	426105	20,000	None
TOTAL PUBLIC TV & RADIO MATCH	**426105**	**20,000**	
Misc Volunteer Involvement Programs- 41 Organizations <$1,000	426106	5,500	None
TOTAL VOLUNTEER INVOLVEMENT PROGRAM	**426106**	**5,500**	
SALVATION ARMY	426107	41,985	None
TOTAL PROJECT SHARE	**426107**	**41,985**	
IDAHO CHAPTER AMERICAN	426108	1,000	None
Misc Education Programs - 7 Organizations <$1,000	426108	3,150	"
TOTAL ENVIROMENT & CONSERVATION	**426108**	**4,150**	
FOUNDATION FOR IDAHO HISTORY,	426109	25,000	None
HILLCREST COUNTRY CLUB	"	5,986	"
IDAHO GOVERNERS CUP	"	18,800	"
UNITED WAY OF TREASURY VALLEY	"	2,000	"
TOTAL NON-PROGRAM	**426109**	**51,786**	"
BOISE STATE UNIVERSITY COLLEGE	426110	2,500	None
COLLEGE OF IDAHO BOX 48	"	3,500	"
COLLEGE OF WESTERN IDAHO FOUND	"	4,700	"
DISCOVERY CENTER OF IDAHO	"	2,500	"
IDAHO STATE UNIVERSITY	"	2,750	"
IDAHO STEM ACTION CENTER	"	1,500	"
JUNIOR ACHIEVEMENT OF IDAHO	"	2,500	"
LEARNING LAB	"	1,000	"
LUPO,MARK J	"	1,068	"
NORTHWEST NAZARENE UNIVERSITY	"	3,500	"
OPEN LAB IDAHO	"	1,000	"
SOCIETY OF WOMEN ENGINEERS	"	3,000	"
TREASURE VALLEY COMMUNITY COLL	"	3,500	"
UNIVERSITY OF IDAHO	"	3,000	"

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Description	Account Number	Total Amount	Amount Assigned to Oregon
Misc Education Programs - 56 Organizations <$1,000	426110	13,166	"
TOTAL EDUCATION	**426110**	**49,183**	
BOISE STATE UNIVERSITY	426111	12,000	None
BRIGHAM YOUNG UNIVERSITY	"	3,000	"
BRIGHAM YOUNG UNIVERSITY IDAHO	"	6,000	"
COLLEGE OF IDAHO BOX 48	"	2,000	"
COLLEGE OF SOUTHERN IDAHO	"	4,000	"
EASTERN OREGON UNIVERSITY	"	2,000	"
IDAHO SCIENCE OLYMPIAD INC	"	2,500	"
IDAHO STATE UNIVERSITY	"	10,000	"
JACKSONVILLE STATE UNIVERSITY	"	2,000	"
MONTANA STATE UNIVERSITY	"	2,000	"
MOUNT MARY UNIVERSITY	"	2,000	"
PORTLAND STATE UNIVERSITY	"	(1,333)	"
ST OLAF COLLEGE	"	2,000	"
UNIVERSITY OF IDAHO	"	8,000	"
WASHINGTON STATE UNIVERSITY	"	2,000	"
WESTMINSTER COLLEGE	"	2,000	"
TOTAL SCHOLARSHIP PROGRAMS	**426111**	**60,167**	"
BOISE STATE UNIVERSITY	426112	1,550	None
BRIGHAM YOUNG UNIVERSITY- IDAH	"	1,000	"
COLLEGE OF IDAHO BOX 48	"	2,000	"
IDAHO STATE UNIVERSITY	"	2,050	"
NORTHWEST NAZARENE UNIVERSITY	"	2,000	"
UNIVERSITY OF IDAHO FOUNDATION	"	6,000	"
Misc Non-Cash Contributions - 7 Organizations <$1,000	"	1,550	"
TOTAL HIGHER EDUCATION MATCH	**426112**	**16,150**	
EEI	426120	15,000	None
TOTAL COMM & TRADE MEMBERSHIPS	**426120**	**15,000**	
CITY OF CALDWELL	426121	3,000	None

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List donations by type and group by the accounts charged. Report whole dollars only. Provide a total for each group

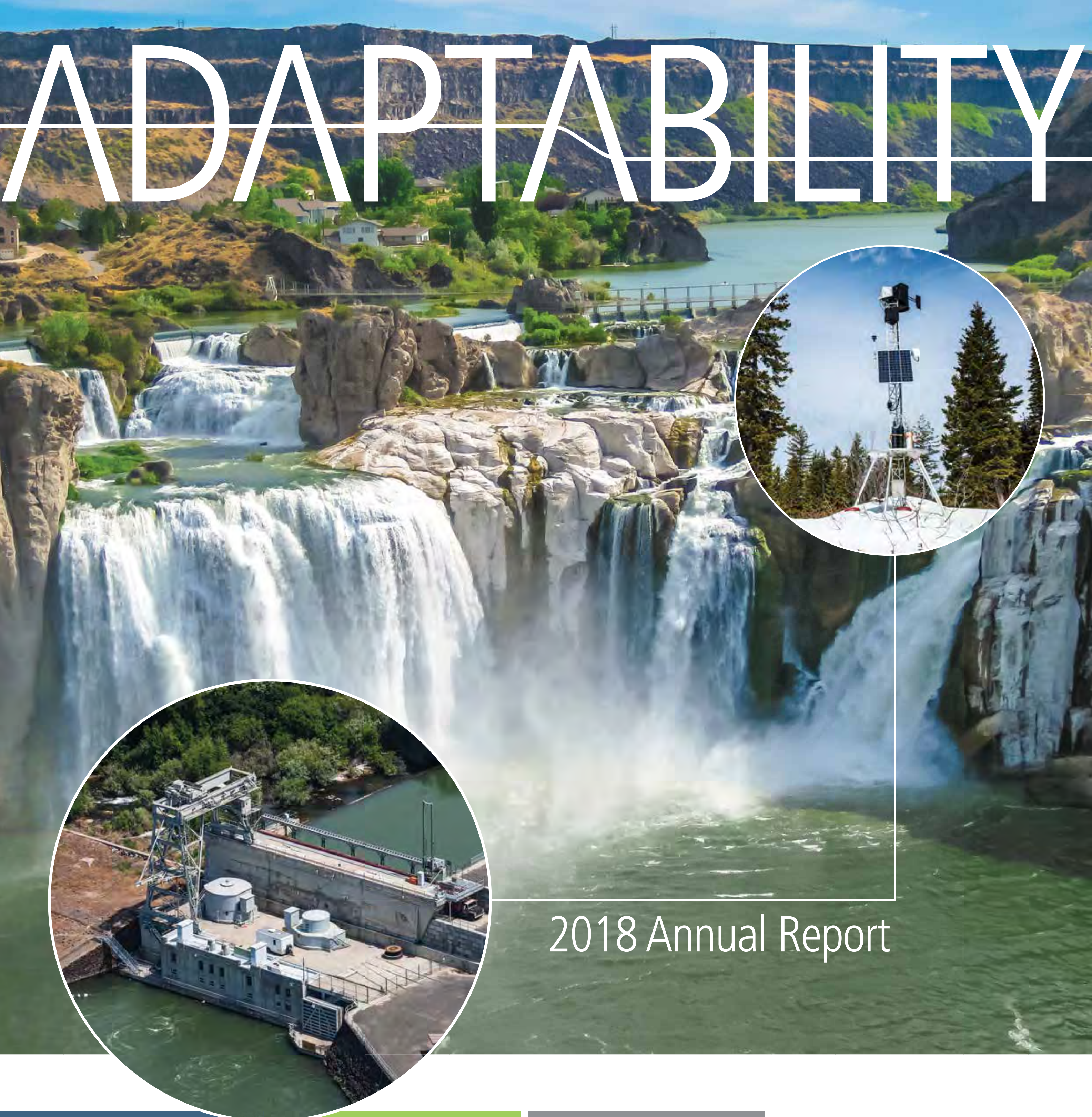
Description	Account Number	Total Amount	Amount Assigned to Oregon
GREAT RIFT BUSINESS DEVELOPMENT	426121	2,275	"
ID DEPT OF COMMERCE	"	3,500	"
KETCHUM INNOVATION CENTER	"	1,500	"
KUNA, CITY OF	"	3,000	"
SOUTHWEST IDAHO MANUFACTURERS	"	1,500	"
SUN VALLEY ECONOMIC DEVELOPMENT	"	1,500	"
Misc Match Higher Education - 8 Organizations <$1000	"	4,528	"
TOTAL ECONOMIC DEVELOPMENT	**426121**	**20,803**	
GRAND VIEW RURAL FIRE PROTECTION	426130	7,500	None
IDAHO CITY FIRE PROTECTION	"	8,500	"
Misc Non-Cash Contributions - 15 Organizations <$1,000	"	822	"
TOTAL NON-CASH CONTRIBUTIONS	**426130**	**16,822**	
TOTAL CONTRIBUTIONS ACCOUNT 426.1		**811,136**	

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	ACS ELECTRICAL SERVICE INC	Electrical Services	$ 1,916
2	AGREE TECHNOLOGIES AND SOLUTIO	Energy Efficiency Services	2,355
3	ANDERSON SCHWARTZMAN WOODARD B	Legal Services	12,874
4	AVERTRA CORPORATION	Management Services	26,405
5	BAKER BOTTS LLP	Legal Services	9,148.30
6	BARKER, ROSHOLT & SIMPSON LLP	Legal Services	37,754
7	BOARDVANTAGE, INC	Management Services	1,223
8	CLEAREDGE PARTNERS INC	Training Consultants	4,113
9	COMPUNET, INC	IT Services	4,806
10	DAVIS WRIGHT TREMAINE LLP	Legal Services	25,002
11	EQ SHAREOWNER SERVICES	Management Services	4,121
12	EVERGREEN CONSULTING GROUP, LL	Management Services	24,146
13	GIVENS PURSLEY LLP	Legal Services	3,320
14	HOLLAND & HART LLP	Legal Services	4,388
15	HONEYWELL INTERNATIONAL INC	Management Services	1,643
16	ICEBERG NETWORKS CORPORATION	IT Services	2,744
17	INTELLITECT	Management Services	2,571
18	J M ROCHE AND ASSOCIATES	Communication Services	2,942
19	MCDOWELL RACKNER & GIBSON PC	Legal Services	20,906
20	NASDAQ CORPORATE SOLUTIONS	Management Services	1,260
21	NIELSEN GROUP INC, THE	IT Services	7,622
22	PERKINS COIE LLP	Legal Services	18,338
23	PW CONSULTING INC	IT Services	2,031
24	QUALITY COMMUNICATIONS INC	Communication Services	2,550
25	QUINTEL-MC INC	IT Services	9,640
26	RESOURCE DATA, INC	IT Services	23,716
27	RM ENERGY CONSULTING	Management Services	15,916
28	SPLUNK PROFESSIONAL	Management Services	1,218.98
29	SULLIVAN & CROMWELL	Legal Services	4,012
30	TETRA TECH MA INC	IT Services	3,791
31	TIBCO SOFTWARE INC	IT Services	6,768
32	TRINOOR LLC	HR Consulting	14,216
33	UNIVERSITY OF IDAHO	Management Services	14,321
34	VAN NESS FELDMAN	Legal Services	32,700
35	WINANDY AND ASSOCIATES LLC	Environmental Services	1,253
36	ZASIO ENTERPRISES	Management Services	3,479
	TOTAL		$ 350,479

ADAPTABILITY



2018 Annual Report

6.7% Earnings Growth

2.3% Customer Growth

6.8% Dividend Growth

IDACORP

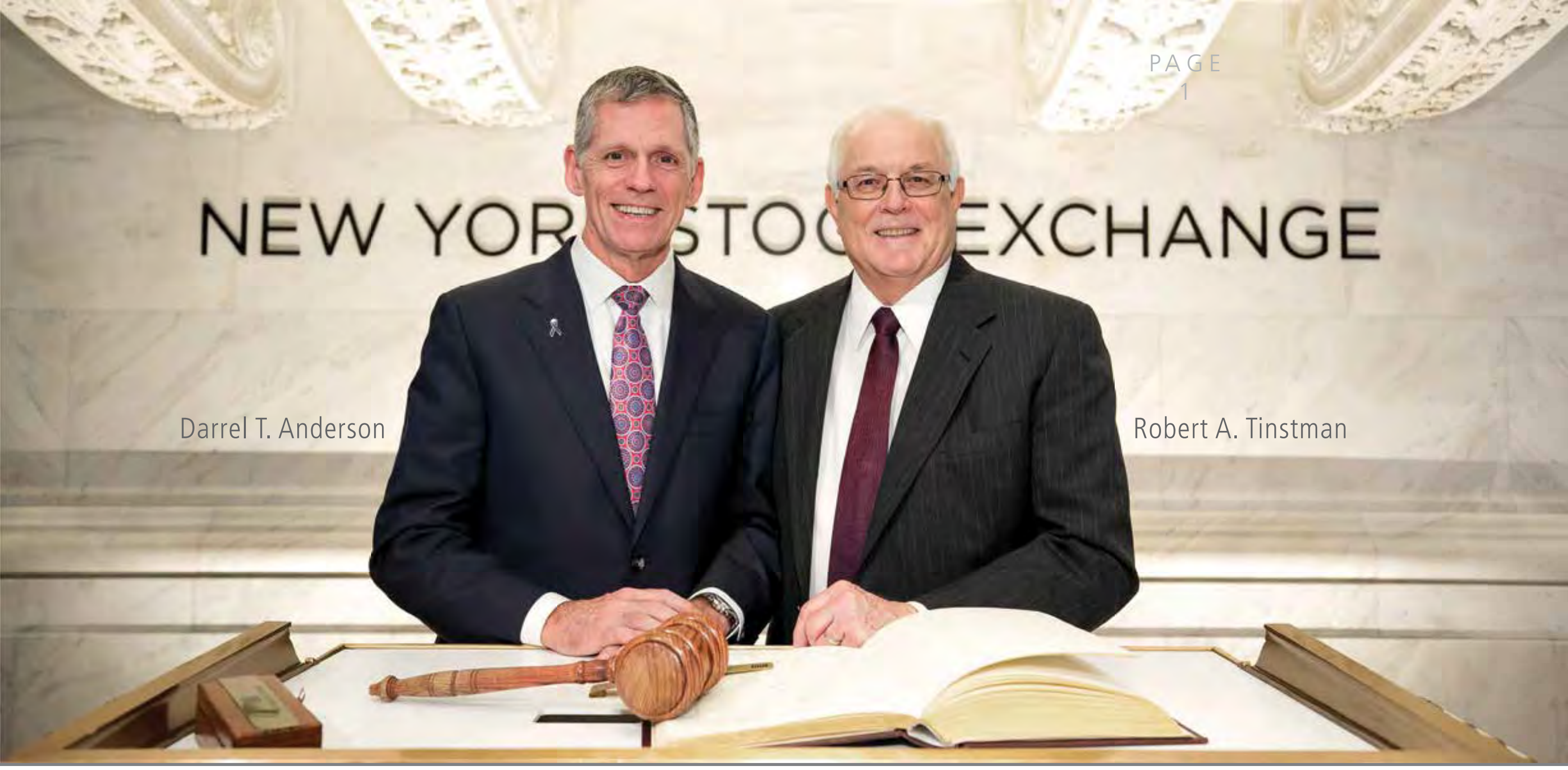
2018 Annual REVIEW

Contents

Highlights

Dollar Amounts in Thousands, Except Per Share Amounts

	2018	2017	% CHANGE
Total Operating Revenues	$1,370,752	$1,349,486	1.58
Net Income	$226,801	$212,419	6.77
Earnings Per Diluted Common Share	$4.49	$4.21	6.65
Dividends Declared Per Common Share	$2.40	$2.24	7.14
Total Assets	$6,382,754	$6,045,405	5.58
Number of Employees (full-time)	1,981	1,972	0.46



IDACORP enjoyed another incredible year of accomplishment in 2018, punctuated by our eleventh consecutive year of earnings growth — a feat that is unprecedented for our company and unique among investor-owned utilities during that period. Idaho Power, IDACORP's primary operating subsidiary, ended the year with record highs in customer satisfaction, as well as electrical grid reliability metrics that were the best ever measured for the company.

2018 saw Idaho Power successfully join the Western Energy Imbalance Market, which has improved our efforts to integrate renewables onto the grid and to more efficiently dispatch our diverse energy mix to power markets throughout the western United States. We reached significant settlements related to federal and state income tax reform in Idaho and Oregon that also addressed the evergreen extension of the earnings support and revenue sharing mechanism in Idaho. We also finished the year having reached a settlement agreement with the states of Oregon and Idaho that now paves the way for the relicensing of the Hells Canyon Hydroelectric Complex, the crown jewel of one of the cleanest generation fleets in the country.

Other notable 2018 accomplishments and milestones include the seventh straight year of meaningful dividend increases, key milestones reached on the Boardman-to-Hemingway and Gateway West 500-kV transmission line projects, and the continued achievement of Idaho Power's carbon dioxide emissions-intensity reduction goal. While each of these achievements is worthy of celebration, we believe the best years are ahead for our company.

We are focused on the future, and the future looks bright. While we recognize additional challenges on the horizon, we will continue to use those as opportunities. We are focused on financial success for shareholders, and we are committed to developing a nimble workforce to meet our customers' changing needs.

We are determined to adapt to these changes by balancing the interests of shareowners, customers, employees and other stakeholders. At Idaho Power, our commitment to serving customers and communities with clean, reliable, fair-priced energy has been the hallmark of our 100-year history. Our diversified energy mix is well-positioned to adapt to changes in our region's climate and our customers' desires. We are clean today, and we are determined to be cleaner tomorrow. Our glide path away from coal, which already includes plans to end our participation in two of three coal-fired power plants, will continue to gain clarity. Our strong hydropower backbone — together with solar, wind and other clean resources — have us on the path toward an even cleaner energy future, while balancing fair prices for all customers.

Robert A. Tinstman
Chairperson of the Board

Darrel T. Anderson
President and Chief Executive Officer

Overview

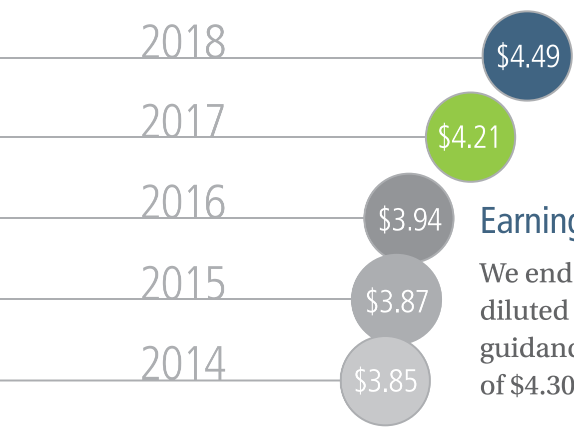
As the energy industry evolves, IDACORP continues to adapt and thrive. In 2018, IDACORP's primary subsidiary, Idaho Power, set new records for energy sales, earnings, customer satisfaction and reliability. As our service area grows and prospers, we continue to innovate and adapt while producing clean, reliable, fair-priced energy for more customers than ever.

Last year marked IDACORP's eleventh consecutive year of earnings growth. Net income increased $14 million from 2017, while Idaho Power was able to reduce customer rates by successfully navigating a federal tax reform giveback to customers, and share $5 million with customers because return on year-end equity exceeded 10 percent.

It was another year of growth across southern Idaho and eastern Oregon. Idaho Power experienced 2.3 percent customer growth as clean energy and competitive prices continued to attract new business and residential customers to our service area. Idaho remains the fastest-growing state in the nation, while its capital city, Boise, moved up 14 spots to No. 12 on the Milken Institute's 2018 list of "Best Performing Cities" thanks to its low business costs and affordable cost of living.

We again preserved tax credits under our Idaho regulatory stipulation for potential use in future years and, more important, extended the earnings support and sharing mechanism indefinitely. The full $45 million of credits remain available for earnings support in future years. IDACORP also received the Edison Electric Institute Electric Utilities Index award for the best total shareholder return performance over the past five years among small-cap utilities (market capitalization of less than $5 billion). IDACORP has received this award twice in the past three years.

Diluted Earnings Per Share

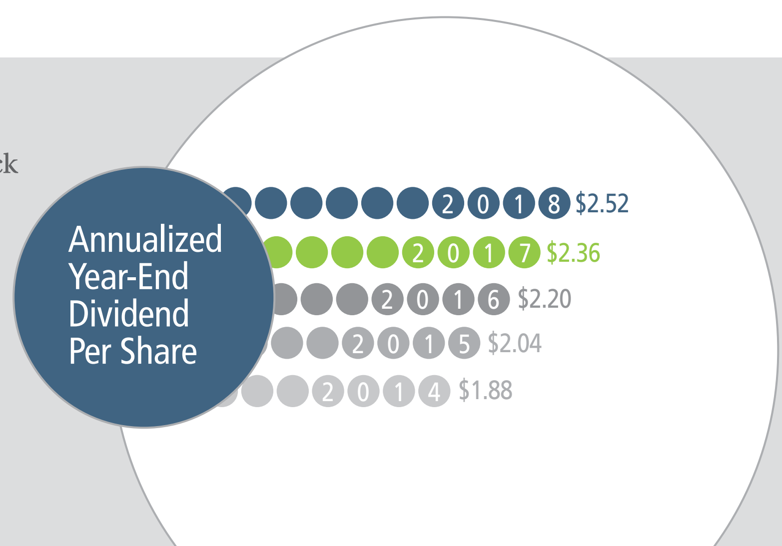


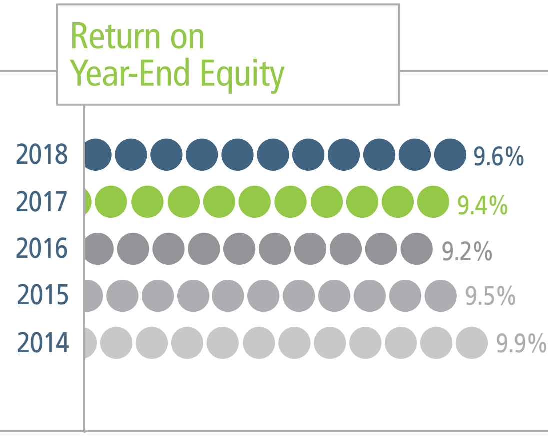
Earnings Guidance

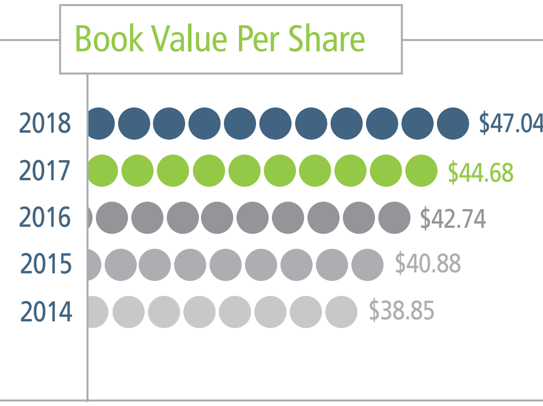
We ended 2018 with earnings of $4.49 per diluted share, and we initiated earnings guidance for the full year 2019 in the range of $4.30 to $4.45 per diluted share.

Dividend Growth

In 2018, IDACORP's quarterly common stock dividend increased from $0.59 per share to $0.63 per share, an increase of 6.8 percent. Management currently expects to recommend to the Board of Directors future annual increases of 5 percent or more to remain near the upper end of the target payout range of between 50 and 60 percent of sustainable IDACORP earnings.



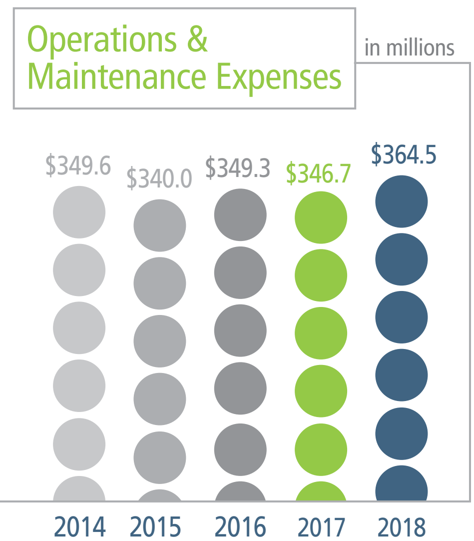


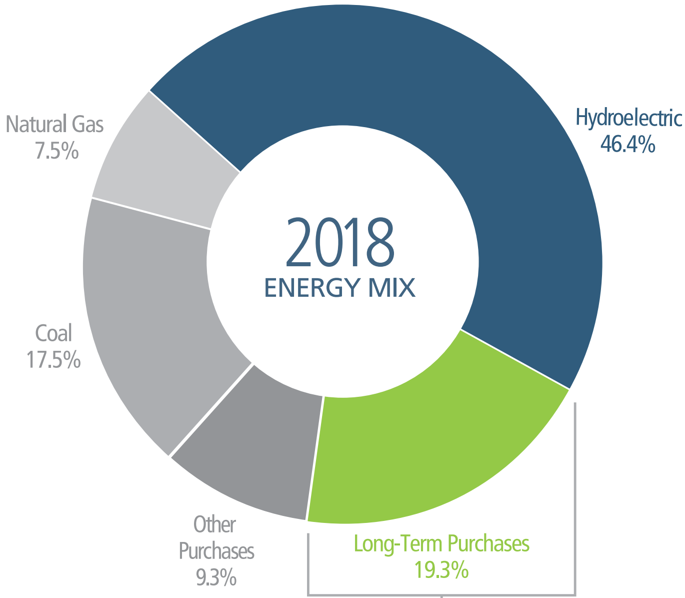


Capital Expenditures

Idaho Power continues to adapt and respond to changes in the energy industry, in part by updating its infrastructure. Ongoing capital projects include upgrading generation plants, replacing underground conductors and continuing to advance the Boardman to Hemingway and Gateway West 500-kilovolt transmission projects. Idaho Power estimates total capital expenditures of nearly $1.5 billion over the next five years.

These infrastructure investments help Idaho Power ensure an adequate supply of electricity, provide service to new customers and maintain system reliability. We expect capital expenditures in the estimated range of $280 million to $290 million for 2019, which remains consistent with recent years.





Adaptable Energy Mix

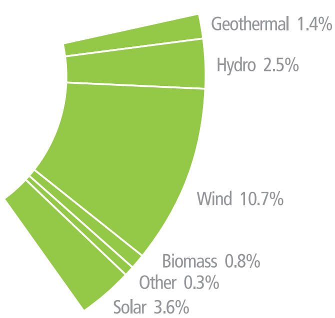
Hydroelectricity remains the backbone of Idaho Power's clean, reliable energy mix. Hydro once again accounted for nearly half of our generation in 2018. Customers continue to be served by a series of 17 hydroelectric projects on the Snake River and its tributaries, as well as three natural gas-fired power plants and portions of three coal-fired plants in which Idaho Power is part owner. Compared with 2017, hydro, coal and natural gas saw minor reductions in generation, while purchased power increased.

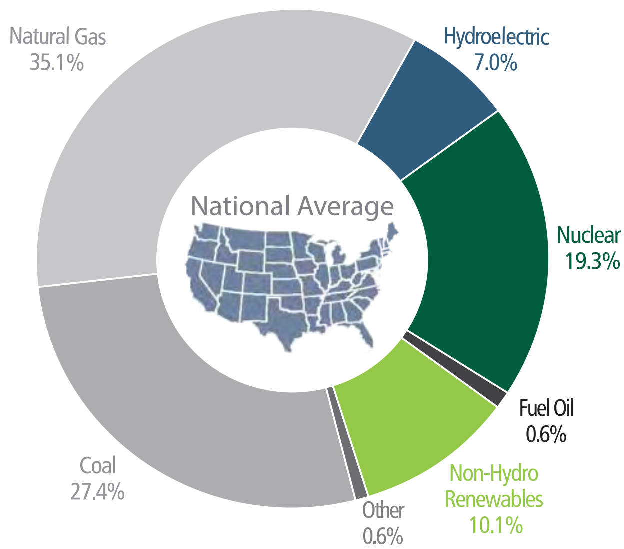
About our Long-Term Purchases

Idaho Power is committed to supporting renewable energy sources, such as wind and solar, and we buy them as part of our portfolio mix. In turn, we sell the Renewable Energy Credits (REC) we get from those purchases to offset power supply costs and keep customer prices as low as possible.

The buyer of a REC gets to claim that power as part of its energy. Therefore, we do not represent that electricity produced by this resource mix is being delivered to our retail customers. We do support these alternate energy sources, and we pass along that credit to the organizations that buy the RECs from us.

The breakdown of our long-term purchases:





Data Source: U.S. Energy Information Administration

500-kilovolt Transmission Projects

The Boardman to Hemingway Transmission Line Project continues to press forward. Idaho Power anticipates the in-service date for this line to be no earlier than 2026, but we expect the Oregon Department of Energy to issue a draft proposed order in 2019, followed by geotechnical investigation in early 2020. Once complete, we expect this line to bring additional clean, affordable energy to our service area.

The Gateway West project is also progressing. This 500-kV line is on schedule to be completed in phases between 2019 and 2024. We project enhanced reliability with the addition of Gateway West.

Hells Canyon

Idaho Power continues to work toward renewing a long-term federal license for the three-dam Hells Canyon Complex, the company's largest generation resource. In April 2018, state regulators approved a settlement agreement allowing approximately $216.5 million in expenditures related to relicensing the Hells Canyon Complex to be designated as prudently incurred and eligible for recovery through customer rates at a later date.

Later in 2018, the states of Idaho and Oregon agreed to a proposed settlement on reintroduction of steelhead and spring Chinook salmon into the Snake River above Oxbow Dam. As part of the settlement, Idaho Power committed to spend an additional $12 million over the first 20 years of the renewed license for research, water quality and stream improvements — key components of meeting our obligations under the federal *Clean Water Act* — and increase hatchery production.

Niagara Springs Hatchery

STEELHEAD & SPRING CHINOOK SALMON

Western Energy Imbalance Market

On April 1, Idaho Power became a full participant in the Western Energy Imbalance Market (EIM). The Western EIM is designed to reduce the power supply cost to serve customers through more efficient dispatch of larger, more diverse resources; to integrate intermittent power from renewable generation resources more effectively; and to enhance reliability.

From April through December 2018, Idaho Power recorded $2.2 million as a regulatory asset within the Idaho Power Cost Adjustment (PCA) balance per the stipulation in the order to match the costs with the benefits of the Western EIM. Participation in the Western EIM was also a factor in Idaho Power increasing its wholesale energy volumes by $28.1 million in 2018 compared to 2017.

Renewables and PURPA

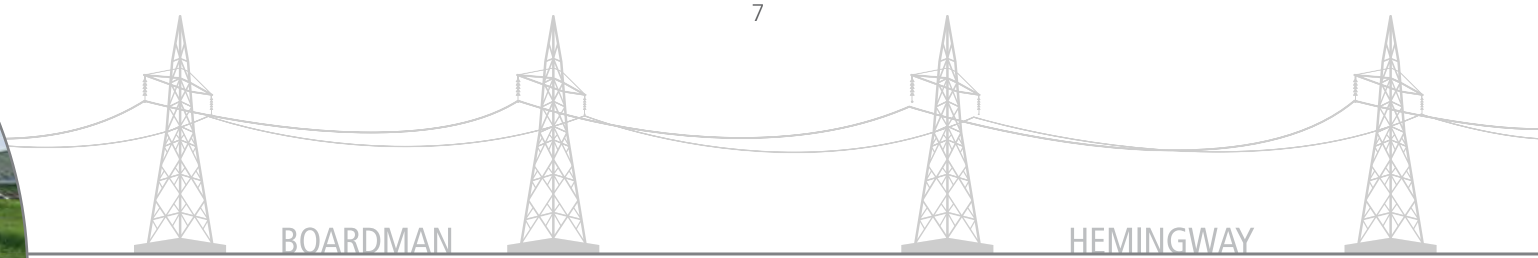
Idaho Power has significant contracts to purchase power from Public Utility Regulatory Policies Act of 1978 (PURPA) Qualifying Facilities (QF) that include renewable generation sources, such as biomass, wind, solar and small hydroelectric. In addition, Idaho Power has non-PURPA power purchase agreements to buy energy from wind and geothermal renewable generation projects, the largest being the Elkhorn Valley wind project with a 101 megawatt (MW) nameplate capacity. As of December 31, 2018, Idaho Power had contracts to purchase generation from 127 PURPA QFs as well as three non-PURPA projects. We also have one new hydroelectric and five solar PURPA QFs expected to come on-line in 2019.

Social and Environmental Responsibility

A clean, adaptable energy mix is helping Idaho Power continue to achieve and exceed its carbon reduction goals. In 2018, the company's carbon dioxide (CO_2) emissions intensity was 647 pounds per megawatt of generation — 46 percent below our baseline year of 2005. Idaho Power's abundance of clean hydroelectricity and long-term resource planning point toward continued CO_2 emissions reductions in the future.

Idaho Power also continued to show environmental stewardship across its service area in 2018. The company is working on habitat improvement projects at Daly Creek in Hells Canyon and Bayha Island in the Mid-Snake River, while efforts are ongoing to protect birds of prey and boost populations of anadromous steelhead and Chinook salmon through hatchery programs. Idaho Power also continues to offer energy efficiency incentives and educate its customers about the benefits of energy efficiency and the wise use of resources.

Lower Salmon Hydroelectric Plant



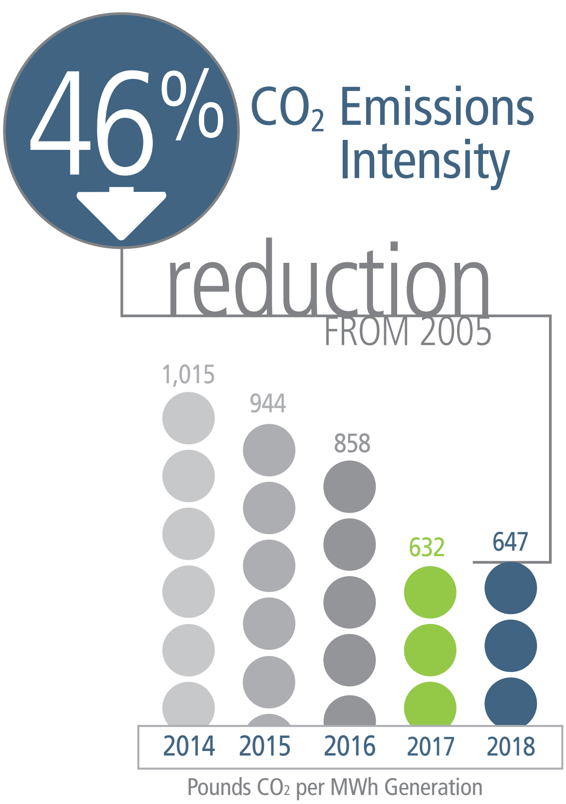
Integrated Resource Plan

Idaho Power plans for infrastructure that will support anticipated growth and allow us to continue to produce clean, reliable, fair-priced energy for our customers. Every two years, Idaho Power updates its Integrated Resource Plan (IRP), with the participation of the many stakeholders who participate on the IRP Advisory Council (IRPAC).

The 2017 IRP was filed with state regulators in June 2017. Key action items identified in the IRP include continued planning for participation in the Western Energy Imbalance Market, planning and coordinating with our operating partners for early retirement of certain coal-fired units, and pre-construction activities for the Boardman-to-Hemingway 500-kilovolt transmission line.

Idaho Power is currently preparing its 2019 IRP, which will be submitted to public utility commissions in Idaho and Oregon in June 2019.

300 MILE 500-kV TRANSMISSION LINE



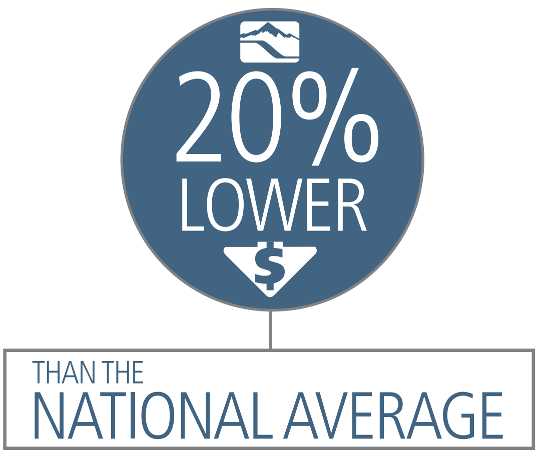
Coal-fired Operations

In February 2019, PacifiCorp filed an alternate regional haze compliance plan with the Wyoming Department of Environmental Quality (DEQ) that would place operational restrictions on the Jim Bridger Power Plant. If approved by the DEQ and the federal Environmental Protection Agency (EPA), this plan would reduce the amount of time the Jim Bridger Plant could operate. The impact would be to reduce emissions to levels at or below what would be achieved by installing additional environmental controls, without incurring the expense of new equipment. This proposal was made in consultation with Idaho Power. The proposal would allow us to comply with the regional haze guidelines while maintaining operational flexibility and system reliability.

At the North Valmy plant in Nevada, Idaho Power finalized negotiations to cease its participation in Unit 1 by the end of 2019. We remain on track to end participation in Unit 2 by the end of 2025. Idaho Power's other coal resource, the Boardman, Oregon, plant in which we are a 10 percent owner, is projected to cease coal-fired operations by the end of 2020.

Competitive Prices

Idaho Power customers continued to enjoy some of the lowest energy rates in the nation in 2018. Thanks to our clean, low-cost hydroelectric power, diverse energy mix and purposeful regulatory strategy, our company continues to earn a fair return for shareholders while keeping customer prices low. Residential customers enjoyed prices 20 percent lower than the national average in 2018, while business prices were 30 percent lower than average. Idaho Power has not filed a general rate case since 2011 and does not anticipate filing one in 2019.



ADITC Extension

Idaho Power did not record any additional Accumulated Deferred Investment Tax Credits (ADITC) amortization during 2018. This preserves the full $45 million of credits available in the regulatory stipulation for future years. Even more importantly, the company reached an agreement on an indefinite extension of this earnings support and sharing mechanism, providing future earnings stability. Increased stability is a win for the company, its customers and its shareowners. Idaho Power expects to continue to practice diligence in managing costs and growing revenues with the goal of preserving credits for future years.

Rate Decreases

Idaho Power, with Idaho Public Utilities Commission (IPUC) approval, decreased rates that saved the average Idaho residential customer 7.06 percent on their monthly bill. The decreases went into effect June 1, 2018. Two of the proposals came from annual mechanisms — the Fixed Cost Adjustment (FCA) and Power Cost Adjustment (PCA) — and the third stemmed from federal and Idaho state income tax-rate changes.

The FCA decreased rates approximately $19.4 million for residential and small general service customers. Residential customers experienced a 3.61-percent decrease. The PCA decreased rates by $22.6 million for all Idaho Power customers. Residential customers saw a 1.29-percent decrease.

Tax reform changes resulted in a total customer benefit of $33.9 million, provided through a base rate reduction of approximately $18.7 million, an additional $7.8 million decrease provided through the 2018 PCA, and a non-cash annual benefit of $7.4 million in the form of an offset to other deferred costs. This decreased residential rates by 2.15 percent.

All Idaho customer classes experienced a rate decrease of at least 4.25 percent in 2018.

Boise, ID

Customer Growth

Idaho Power continues to see substantial growth within its service area — its customer base grew by 2.3 percent in 2018 and employment grew by approximately 2.2 percent. Our total customer base has grown to nearly 560,000. Customer growth in Idaho Power's service area continues to positively impact revenues.

2.3%

NEARLY 560,000 CUSTOMERS

Economic Development

Idaho's economy continued to thrive in 2018. Customer growth brought new business customers to Idaho Power's service area, and Moody's gross domestic product (GDP) forecast calls for continued economic growth going forward. Employment in our region has grown to a record of nearly 525,000 people.

Economic development brings opportunities for large commercial and industrial growth. Idaho Power's energy sales for this customer segment increased nearly 1 percent over the record-breaking numbers we saw in 2017. Large load growth primarily came from expansion projects of existing customers, along with several new customers investing in our service area. Idaho Power also experienced a balanced mix of growth within our core industry focus, including major additions and expansions in food processing, manufacturing and data centers and technology.

Customer Satisfaction & Reliability

Adaptability extends beyond Idaho Power's balanced energy mix and business strategy. Our company also works hard to focus on and meet our customers' ever-changing needs. Idaho Power undertook several projects to improve customer touchpoints in 2018, including improving our website, redesigning our monthly bill and offering new online services. Customer response was outstanding — the company earned the highest customer satisfaction scores in its history, finishing at or near the top of our western, mid-sized investor-owned utility peers in every category.

Reliability also enjoyed a benchmark year in 2018. On average, our customers only experienced about one outage longer than five minutes.

Looking Forward

IDACORP had a momentous year of growth and success in 2018. From achieving an eleventh consecutive year of earnings growth to earning the best customer satisfaction scores in company history, Idaho Power continued to thrive thanks to the hard work and dedication of our nearly 2,000 employees.

As we look forward, Idaho Power is well positioned to meet the challenges ahead. Our company's clean energy mix, purposeful regulatory strategy and dedicated employees will continue to adapt to a changing energy industry, ensuring future success for our company and shareowners and a positive experience for our customers. By embracing growth, adjusting to technological changes and keeping our customers' needs at the forefront, we expect Idaho Power to continue to grow its financial strength, improve its core business and enhance its brand.

Thank you for your continued investment in IDACORP. We appreciate your support, and we look forward to another great year in 2019.

ADAPTABILITY

BOARD OF DIRECTORS

IDACORP & IDAHO POWER

Robert A. Tinstman*
(1999) Boise, Idaho
Former Executive Chairman of James Construction Group; former President and Chief Executive Officer and Director of Morrison–Knudsen Corp.; Director of Primoris Services Corp.; Director of Westmoreland Coal Company; former Director of CNA Surety and Home Federal Bancorp, Inc.

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 and former President and Chief Executive Officer of James Campbell Company, LLC; Director, Dine Brands Global, Inc.; Director, Hawaiian Electric Industries, Inc. and Hawaii Electric Company; former President and Chief Operating Officer of Dole Food Company.

Annette G. Elg
(2017) Boise, Idaho
Former Senior Vice President and Chief Financial Officer of J.R. Simplot Company; former Vice President and Controller of J.R. Simplot Company; former Director of Cascade Bancorp

Ronald W. Jibson
(2013) North Salt Lake City, Utah
Former President and Chief Executive Officer and Director and Chairman of the Board of Questar Corporation; former President and Chief Executive Officer of Wexpro Corporation and Questar Gas Company; former Chairman of the Board of Directors of Questar Pipeline Company; Director of Dominion Energy, Inc.

Judith A. Johansen
(2007) Scottsdale, Arizona
Former President of Marylhurst University; former President and Chief Executive Officer of PacifiCorp; former Chief Executive Officer and Administrator of the Bonneville Power Administration; Director of Schnitzer Steel and Roseburg Forest Products; former Director of Pacific Continental Corporation.

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 First Interstate Bancorp; former Director of Cascade Bancorp.

Christine King
(2006) Scottsdale, Arizona
Former President and Chief Executive Officer of Standard Microsystems Corporation; former Chief Executive Officer and Director of AMI Semiconductor; Director of Skyworks Solutions, Inc.; former Director and Executive Chair of QLogic Corp., former Director of Cirrus Logic, Inc.

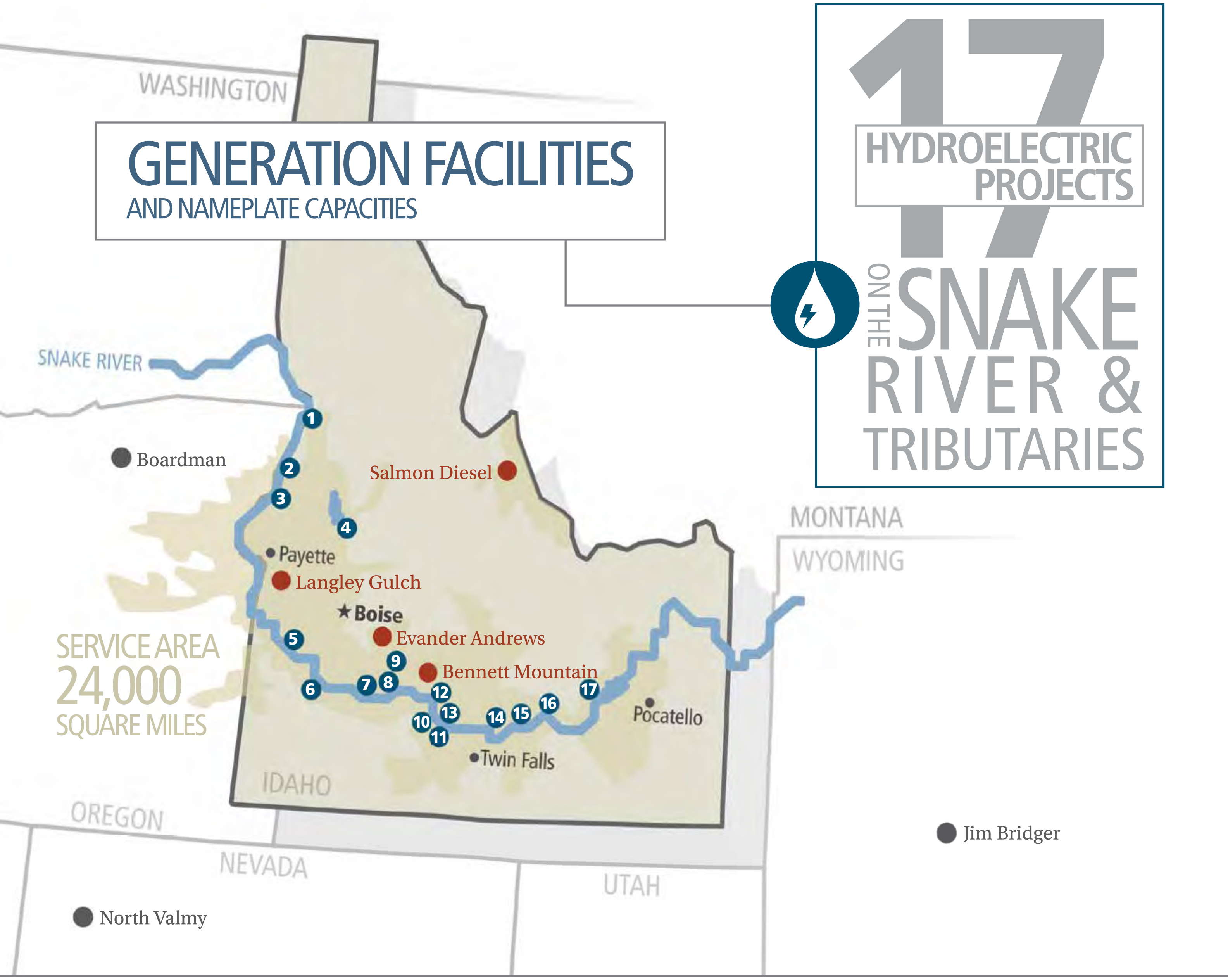
Richard J. Navarro
(2015) Boise, Idaho
Former Chief Financial Officer of Albertson's, LLC; former Chief Administrative Officer at Albertson's, LLC.; former Director of Home Federal Bancorp, Inc.

Average Tenure	7.5 years
Average Age	66 years
Independent	90 percent
Gender Diversity	30 percent

( ) year appointed or elected to the board

* Chairperson of the Board

GENERATION FACILITIES
AND NAMEPLATE CAPACITIES



Hydroelectric Facilities

1	Hells Canyon	391,500 kW
2	Oxbow	190,000 kW
3	Brownlee	654,100 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	6,800 kW
13	Clear Lake	2,500 kW
14	Shoshone Falls	11,500 kW
15	Twin Falls	52,897 kW
16	Milner	59,448 kW
17	American Falls	92,340 kW

Thermal Facilities

Jim Bridger	770,501 kW[1]
North Valmy	283,500 kW[1]
Boardman	64,200 kW[1]
Evander Andrews	270,900 kW[2]
Bennett Mountain	172,800 kW
Salmon Diesel	5,000 kW
Langley Gulch	318,452 kW

[1] Idaho Power share [2] Danskin

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the fiscal year ended December 31, 2018

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 Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) 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 (§ 229.405 of this chapter) 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, smaller reporting companies, or emerging growth companies. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

IDACORP, Inc.:
Large accelerated filer X Accelerated filer __ Non-accelerated filer __
Smaller reporting company __
Emerging growth company __

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. __

Idaho Power Company:
Large accelerated filer __ Accelerated filer __ Non-accelerated filer X
Smaller reporting company __
Emerging growth company __

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. __

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, 2018):

IDACORP, Inc.:	$ 4,611,144,658	Idaho Power Company:	None

Number of shares of common stock outstanding as of February 15, 2019:

IDACORP, Inc.:	50,383,366
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 2019 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.

TABLE OF CONTENTS

* 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 2019 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

AOCI - Accumulated Other Comprehensive Income

APCU - Annual Power Cost Update

ASU - Accounting Standards Update

BCC - Bridger Coal Company, a joint venture of IERCo

BLM - U.S. Bureau of Land Management

CAA - Clean Air Act

CO_2 - Carbon Dioxide

CWA - Clean Water Act

EIS - Environmental Impact Statement

EPA - U.S. Environmental Protection Agency

ESA - Endangered Species Act

FASB - Financial Accounting Standards Board

FCA - Idaho Fixed Cost Adjustment

FERC - Federal Energy Regulatory Commission

FPA - Federal Power Act

GAAP - Generally Accepted Accounting Principles

GHG - Greenhouse Gas

HCC - Hells Canyon Complex

IDACORP - IDACORP, Inc., an Idaho Corporation

Idaho Power - Idaho Power Company, an Idaho Corporation

Idaho ROE - Idaho-jurisdiction return on year-end equity

Ida-West - Ida-West Energy Company, a subsidiary of IDACORP, Inc.

IERCo - Idaho Energy Resources Co., a subsidiary of Idaho Power Company

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

kWh - Kilowatt-hour

LTICP - IDACORP 2000 Long-Term Incentive and Compensation Plan

MATS - Mercury and Air Toxics Standards

MD&A - Management's Discussion and Analysis of Financial Condition and Results of Operations

MMBtu - Million British Thermal Units

MW - Megawatt

MWh - Megawatt-hour

NAAQS - National Ambient Air Quality Standards

NEPA - National Environmental Policy Act

NMFS - National Marine Fisheries Service

NOAA Fisheries - National Oceanic and Atmospheric Administration's National Marine Fisheries Service

NO_2 - Nitrogen Dioxide

NO_x - Nitrogen Oxide

O&M - Operations and Maintenance

OATT - Open Access Transmission Tariff

OPUC - Public Utility Commission of Oregon

PCA - Idaho-jurisdiction Power Cost Adjustment

PCAM - Oregon Power Cost Adjustment Mechanism

PEIS - Programmatic Environmental Impact Statement

PURPA - Public Utility Regulatory Policies Act of 1978

REC - Renewable Energy Certificate

RH BART - Regional haze - best available retrofit technology

RPS - Renewable Portfolio Standard

SEC - U.S. Securities and Exchange Commission

SCR - Selective catalytic reduction equipment

SMSP - Security Plan for Senior Management Employees

SO_2 - Sulfur Dioxide

USFWS - U.S. Fish and Wildlife Service

Valmy Plant - North Valmy coal-fired power plant

Western EIM - Energy imbalance market implemented in the western United States

WPSC - Wyoming Public Service Commission

WDEQ - Wyoming Department of Environmental Quality

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. (IDACORP) and Idaho Power Company (Idaho Power) 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, future events, or performance, often, but not always, through the use of words or phrases such as "anticipates," "believes," "continues," "could," "estimates," "expects," "guidance," "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 U.S. Securities and Exchange Commission, and the following important factors:

- the effect of decisions by the Idaho and Oregon public utilities commissions and the Federal Energy Regulatory Commission that impact Idaho Power's ability to recover costs and earn a return on investment;
- the expense and risks associated with capital expenditures for utility infrastructure, and the timing and availability of cost recovery for such expenditures through customer rates, including the potential for the write-down or write-off of expenditures if not deemed prudent by regulators;
- changes in residential, commercial, and industrial growth and demographic patterns within Idaho Power's service area, the loss or change in the business of significant customers, or the addition of new customers, and their associated impacts on loads and load growth, and the availability of regulatory mechanisms that allow for timely cost recovery through customer rates in the event of those changes;
- the impacts of economic conditions, including inflation, interest rates, regulatory authorized returns on equity, supply costs, population growth or decline in Idaho Power's service area, changes in customer demand for electricity, revenue from sales of excess power, credit quality of counterparties and suppliers, and the collection of receivables;
- unseasonable or severe weather conditions, wildfires, drought, and other natural phenomena and natural disasters, including conditions and events associated with climate change, which affect customer demand, hydroelectric generation levels, repair costs, liability for damage caused by utility property, and the availability and cost of fuel for generation plants or purchased power to serve customers;
- advancement of self-generation, energy storage, and energy efficiency technologies that may affect Idaho Power's sale or delivery of electric power or introduce new cyber security risks;
- 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;
- 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 associated 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 acquire 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 affecting or caused by Idaho Power facilities or infrastructure), explosions, and mechanical breakdowns that may occur while operating and maintaining Idaho Power assets, 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 for which the companies may have inadequate insurance coverage;
- the increased purchased power costs and operational challenges associated with purchasing and integrating intermittent renewable energy sources into Idaho Power's resource portfolio;

- disruptions or outages of Idaho Power's generation or transmission systems or of any interconnected transmission systems may constrain resources or cause Idaho Power to incur repair costs and purchase replacement power at increased costs;
- 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 or disruptions 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 debt and equity markets, increase borrowing costs, and 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 and the companies' cash flows;
- the ability to continue to pay dividends based on financial performance and in light of contractual covenants and restrictions and regulatory limitations;
- 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 attract and retain skilled workers, and the ability to adjust the labor cost structure when necessary;
- failure to comply with state and federal laws, regulations, and orders, 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 resulting operational changes through insurance or rates, or from third parties;
- the companies' failure to secure data or to comply with privacy laws or regulations, security breaches, or the disruption or damage to the companies' business, operations, or reputation resulting from cyber-attacks and related litigation or penalties, terrorist incidents or the threat of terrorist incidents, or other malicious acts, 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 U.S. 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. As of December 31, 2018, IDACORP had 1,981 full-time employees, 1,972 of whom were employed by Idaho Power, and 9 part-time employees, 7 of whom were employed by Idaho Power.

IDACORP’s other notable subsidiaries include IDACORP Financial Services, Inc. (IFS), an investor in affordable housing and other real estate investments, and 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).

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.

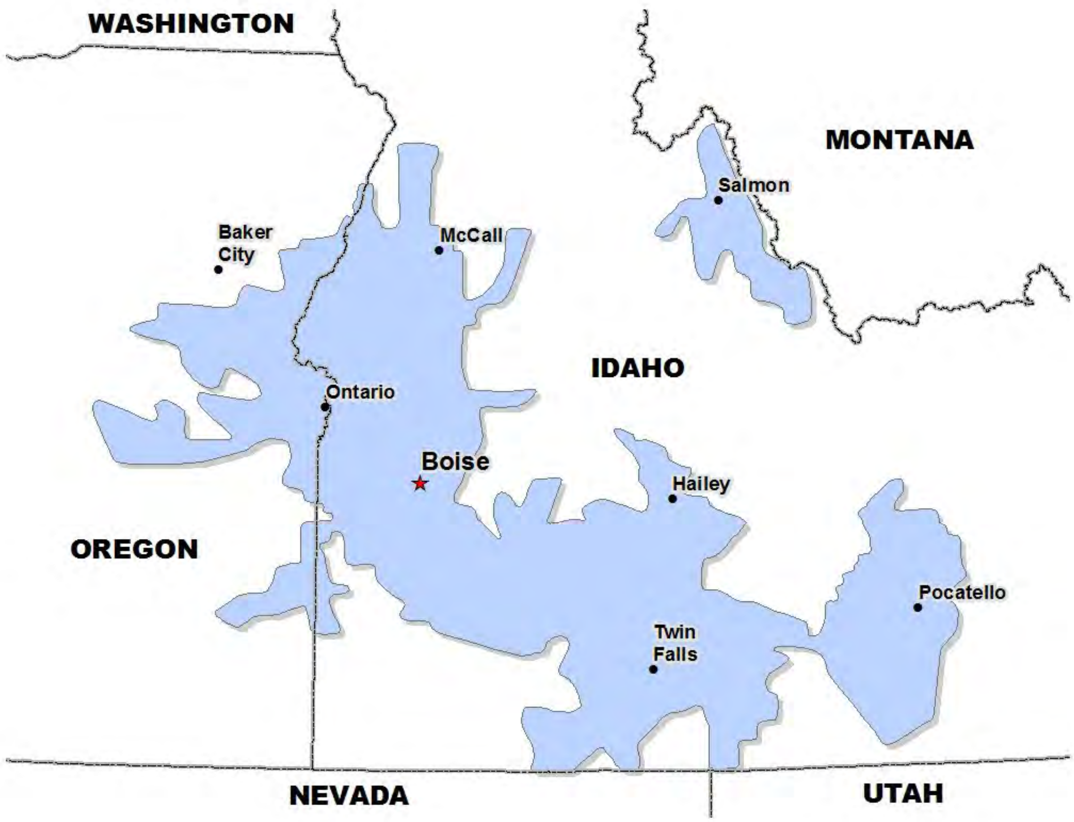
Available Information

IDACORP and Idaho Power make available free of charge on their websites their Annual Reports 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.

UTILITY OPERATIONS

Background

Idaho Power provided electric utility service to more than 558,000 retail customers in southern Idaho and eastern Oregon as of December 31, 2018. Approximately 465,000 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 72 cities in Idaho and 7 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 1.2 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 retail customers. Idaho Power is also under the regulatory jurisdiction of the IPUC, the OPUC, and the Wyoming Public Service Commission (WPSC) as to the issuance of debt and equity securities. As a public utility under the Federal Power Act (FPA), Idaho Power has authority to charge market-based rates for wholesale energy sales under its FERC tariff and to provide transmission services under its open access transmission tariff (OATT). 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 (GAAP), 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 or when otherwise directed to begin amortization by a regulator. 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 expects the amounts will be reflected in future prices, based on regulatory orders or other available evidence.

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 those adjustments as regulatory assets or liabilities if it is probable that the amounts will be recovered from or returned to customers in future rates.

Business Strategy

IDACORP is committed to its focus on competitive total returns and generating long-term value for shareholders. IDACORP's business strategy emphasizes Idaho Power as IDACORP's core business, as Idaho Power's regulated utility operations are the primary driver of IDACORP's operating results. IDACORP's board of directors regularly reviews IDACORP's long-term strategy, which as of the date of this report is focused on the following areas and initiatives:

Focus Areas	Initiatives
Grow to Enhance Financial Strength	- Execute on Business Development Initiatives - Find New Revenue Opportunities - Promote and Engage in Beneficial Electrification
Improve the Core Business	- Implement/Utilize Value-Added Analytics and Machine Learning - Upgrade Infrastructure for Growth, Technology Changes, Renewable Energy Integration, and Flexibility - Evaluate and Control Expenditures and Continue Efficient Operations - Use Technology to Enhance the Grid, System Reliability, and Safety - Implement Rate Structures that are Fair and Reasonable to All Customers - Leverage Technology and Turn Disruptive Threats into Opportunities
Enhance Idaho Power's Brand	- Enhance Idaho Power's Customers' Experience and Interactions - Continue Environmental Stewardship and Emission Reductions - Continue Constructive Regulatory Relationships and a Regulatory Compliance Mindset - Communicate Idaho Power's Story
Focus on Safety & Employee Engagement	- Continue Idaho Power's Strong Focus on Safety and Reducing Injuries - Execute on Employee Engagement and Leadership Development Initiatives

In executing the focus areas above, IDACORP seeks to balance the interests of shareholders, Idaho Power customers, employees, and other stakeholders. Idaho Power is working to continue to provide safe, fair-priced, reliable service to its customers from diversified generation resources, with a continued commitment to strong, sustainable financial results and strong credit ratings.

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 electric power and services are critical factors 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'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. Idaho Power regularly evaluates the need to request changes to its retail electricity price structure to cover its operating costs and to earn a fair return on its investments. Idaho Power uses general rate cases, power cost adjustment mechanisms in Idaho and Oregon, a fixed cost adjustment (FCA) mechanism in Idaho, 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, 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 accrued for refund. Deferred amounts are generally collected from and accrued amounts are generally 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 power cost adjustment mechanisms, FCA mechanism, and energy efficiency riders. Idaho Power collects most of its energy efficiency program costs through energy efficiency riders on customer bills. The Idaho and Oregon power cost adjustment 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 or refund 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, applicable to Idaho residential and small commercial customers, is designed to remove a portion of 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. Under Idaho Power's current rate design, recovery of a portion of fixed costs is included in the variable kilowatt-hour charge, which may result in overcollection or undercollection of fixed costs. To return overcollection to customers or to collect undercollection from customers, the FCA mechanism allows Idaho Power to accrue, or defer, the difference between the authorized fixed-cost recovery amount per customer and the actual fixed costs per customer recovered by Idaho Power during the year. Increases in FCA recovery are capped at 3 percent of base revenue annually, with any excess deferred for collection in a subsequent year.

***Wholesale Markets*:** 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 wholesale energy sales depend largely on the availability of generation resources above the amount necessary to serve customer loads as well as market power prices at the time when those resources are available. A reduction in either factor leads to lower wholesale energy sales.

Idaho Power's OATT rate is revised each year based primarily on financial and operational data Idaho Power files annually with the FERC in its Form 1. The FERC oversees mandatory transmission and network reliability standards, as well as power and transmission markets, including protection against market manipulation. These mandatory transmission and reliability standards were developed by the North American Electric Reliability Corporation and the Western Electricity Coordinating Council, which have responsibility for compliance and enforcement of transmission and reliability standards.

Retail Energy Sales: Weather, seasonal customer demand, energy efficiency, 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 during the winter heating season. Extreme temperatures increase sales to customers who use electricity for cooling and heating, and mild temperatures decrease sales. Increased precipitation levels during the agricultural growing season reduce electricity sales to customers who use electricity to operate irrigation pumps. Alternative methods of generation, including customer-owned solar and other forms of distributed generation, have the potential to decrease Idaho Power sales to existing customers. Also, development of new technologies and services to help energy consumers manage energy in new ways could continue to alter demand for Idaho Power's electric energy. Approximately 95 percent of Idaho Power's retail 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."

The table that follows presents Idaho Power’s revenues and sales volumes for the last three years, classified by customer type.

	Year Ended December 31,		
	2018	2017	2016
Retail revenues (thousands of dollars):			
Residential (includes $34,625, $17,320, and $29,170, respectively, related to the FCA[(1)])	$ 530,527	$ 552,333	$ 514,954
Commercial (includes $1,299, $876, and $1,087, respectively, related to the FCA[(1)])	310,299	319,195	302,650
Industrial	190,130	195,124	182,590
Irrigation	158,001	150,030	156,505
Provision for sharing	(5,025)	—	—
Deferred revenue related to HCC relicensing AFUDC[(2)]	(8,780)	(10,706)	(10,706)
Total retail revenues	1,175,152	1,205,976	1,145,993
Wholesale energy sales	52,845	24,790	11,900
Transmission wheeling revenues	59,094	43,970	32,496
Energy efficiency program revenues	35,703	39,241	33,754
Other revenues	43,788	30,916	35,210
Total electric utility operating revenues	$ 1,366,582	$ 1,344,893	$ 1,259,353
Energy sales (thousands of Megawatt-hour (MWh)):			
Residential	5,135	5,355	5,004
Commercial	4,105	4,099	3,999
Industrial	3,371	3,346	3,243
Irrigation	1,976	1,771	1,950
Total retail energy sales	14,587	14,571	14,196
Wholesale energy sales	2,246	1,934	742
Bundled energy sales	617	202	444
Total energy	17,450	16,707	15,382

(1) The FCA mechanism is an alternative revenue program in the Idaho jurisdiction and does not represent revenue from contracts with customers as disclosed in Note 4 – “Revenues” to the consolidated financial statements included in this report.

(2) As part of its January 30, 2009, general rate case order, the IPUC is allowing Idaho Power to recover a portion of the allowance for funds used during construction (AFUDC) on construction work in progress related to the Hells Canyon Complex (HCC) relicensing process, even though the relicensing process is not yet complete and the costs have not been moved to electric plant in service. Idaho Power is collecting $8.8 million annually in the Idaho jurisdiction but is deferring revenue recognition of the amounts collected until the license is issued and the accumulated license costs approved for recovery are placed in service. Prior to the May 2018 Idaho Tax Reform Settlement Stipulation, described in Note 3 – “Regulatory Matters” to the consolidated financial statements included in this report, Idaho Power was collecting $10.7 million annually.

Competition: Idaho Power's electric utility business has historically been recognized as a natural monopoly. Idaho Power competes with fuel distribution companies, including natural gas providers, 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.

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 power cost adjustment mechanisms mitigate in large part the financial impacts of volatile fuel and power costs.

Idaho Power's system is dual peaking, with the larger peak demand occurring in the summer. Idaho Power reached its highest all-time system peak demand of 3,422 megawatts (MW) on July 7, 2017. Idaho Power's highest all-time winter peak demand of 2,527 MW was last achieved on January 6, 2017. 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.

	Power Supply			Percent of Total Generation		
	2018	2017	2016	2018	2017	2016
	(thousands of MWh)					
Hydroelectric plants	8,682	8,900	6,408	65%	65%	53%
Coal-fired plants	3,274	3,284	4,045	24%	24%	33%
Natural gas-fired plants	1,408	1,504	1,722	11%	11%	14%
Total system generation	13,364	13,688	12,175	100%	100%	100%
Purchased power - cogeneration and small power production	3,045	2,800	2,314			
Purchased power - other	2,386	1,442	2,023			
Total purchased power	5,431	4,242	4,337			
Total power supply	18,795	17,930	16,512			

***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 1,775 MW and annual generation of approximately 8.7 million MWh under median water conditions. The amount of water available for hydroelectric power generation depends on several factors—the amount of snowpack 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.

In 2018, reservoir storage carryover from the previous year coupled with near-normal winter snowpack resulted in 8.7 million MWh of hydroelectric generation. In 2017, above normal winter and spring precipitation resulted in 8.9 million MWh of hydroelectric generation. In 2016, low upstream reservoir carryover (primarily in the upper Snake River basin) resulted in reduced downstream flow releases. Additionally, although snowpack accumulation was near-normal on April 1, 2016, the snowpack melted earlier than usual. The combined effect was lower than median hydro production of 6.4 million MWh in 2016. During low water years, when stream flows into Idaho Power's hydroelectric projects are reduced, Idaho Power's hydroelectric generation is reduced, resulting in a greater reliance on other generation resources and wholesale power purchases. For 2019, Idaho Power estimates annual generation from its hydroelectric facilities to be between 6.5 million MWh and 8.5 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 HCC, 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.

BCC supplies coal to the Jim Bridger power plant. IERCo, a wholly-owned subsidiary of 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 through 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 2021 from the Black Butte mine located near the Jim Bridger plant. This contract supplements the BCC deliveries and provides another coal supply to fuel 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 (Valmy Plant). Idaho Power expects to meet 2019 fuel requirements through existing inventory and coal contracts and expects to be able to meet future coal requirements through new or existing coal supply contracts. In 2017 and 2018, Idaho Power established a process approved by the IPUC and OPUC for recovery of costs related to Idaho Power's plan to end its participation in coal-fired operations at the Valmy Plant units 1 and 2 in 2019 and 2025, respectively. In 2018, the Valmy Plant provided 5 percent of Idaho Power's total generation, compared with 2 percent of Idaho Power's total generation in both 2017 and 2016.

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 2019. 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, 2018, approximately 6.4 million MMBtu of natural gas was financially hedged for physical delivery for the operational dispatch of the Langley Gulch plant through January 2020. 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 requirements, 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 2018 and 2017, Idaho Power purchased 1.4 million MWh and 0.9 million MWh of power through wholesale market purchases at an average cost of $31.55 per MWh and $26.32 per MWh, respectively. During 2018 and 2017, Idaho Power sold 2.2 million MWh and 1.9 million MWh of power in wholesale market sales, with an average price of $23.53 per MWh and $12.82 per MWh, respectively.

Long-term Power Purchase and Exchange Arrangements: In addition to its wholesale market purchases, Idaho Power has the following notable long-term power purchase contracts and energy exchange agreements:

- Telocaset Wind Power Partners, LLC - for 101 MW (nameplate generation) from the Elkhorn Valley wind project located in eastern Oregon. The contract term ends in 2027.
- USG Oregon LLC - for 22 MW (estimated average annual output) from the Neal Hot Springs Unit #1 geothermal power plant located near Vale, Oregon. The contract term ends in 2037.
- Clatskanie People's Utility - for up to 18 MW of generation 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 contract term ends in 2020. Idaho Power has the right to renew the agreement for an additional five-year term.
- Raft River Energy I, LLC - for up to 13 MW (estimated average annual output) from its Raft River Geothermal Power Plant Unit #1 located in southern Idaho. The contract term ends in 2033.

PURPA Qualifying Facility Energy Sales Agreements: Idaho Power purchases power from PURPA qualifying facilities as mandated by federal law. As of December 31, 2018, Idaho Power had contracts with on-line PURPA qualifying facilities with a total of 1,119 MW of nameplate generation capacity, with an additional 29 MW nameplate capacity of projects projected to be on-line in 2019. The energy sales agreements for these qualifying facilities have original contract terms ranging from one to 35 years. The expense and volume of purchases from PURPA qualifying facilities during the last three years is included in the following table:

	Year Ended December 31,		
	2018	**2017**	**2016**
PURPA contracts expense (in thousands)	$ 189,722	$ 169,788	$ 153,665
MWh purchased under PURPA contracts (in thousands)	3,045	2,800	2,314
Average cost per MWh from PURPA contracts	$ 62.31	$ 60.64	$ 66.41

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 energy sales agreements under each state's jurisdiction. For PURPA energy sales agreements:

- Idaho Power is required to purchase all of the output delivered from the contracted qualifying 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 qualifying 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 Idaho-jurisdiction power cost adjustment (PCA) mechanism, and the OPUC jurisdictional portion is recovered through base rates and an Oregon power cost recovery mechanism. Thus, the primary impact of high power purchase costs under PURPA contracts is on customer rates.

- OPUC jurisdictional regulations have generally provided for PURPA standard contract terms of up to 20 years.
- 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 IPUC issued an order in August 2015 that revised the standard PURPA power purchase contract term for new contracts to a 2-year term from the previously required 20-year term for qualifying facilities that exceed the size limitations for published avoided costs.
- The OPUC requires that Idaho Power pay the published avoided costs for solar PURPA qualifying facilities with a nameplate rating of 3 MW or less and all other types of projects with a nameplate rating of 10 MW or less. Idaho Power is required to negotiate an applicable price (premised on avoided costs) for all other qualifying facilities based upon OPUC regulations.

Participation in Western Energy Imbalance Market: In 2014, the California Independent System Operator and PacifiCorp implemented an energy imbalance market (Western EIM) under which the participating parties enabled their systems to interact for automated intra-hour economic dispatch of generation from committed resources to serve loads. 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. Idaho Power commenced participation in the Western EIM in April 2018. For information on regulatory proceedings related to costs associated with joining the Western EIM, see Part II, Item 7 – MD&A - "Regulatory Matters - Western Energy Imbalance Market Costs."

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, the transmission grid covering much of western North America. Idaho Power provides wholesale transmission service for eligible transmission customers on a non-discriminatory basis. Idaho Power is a member of the Western Electricity Coordinating Council, the Northwest PowerPool, 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 1,000-mile, 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 2017. 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.

In 2018, Idaho Power began preparing its 2019 IRP. The load forecast assumptions Idaho Power expects to use in its 2019 IRP are included in the table below, together with the average annual growth rate assumptions used in the prior two IRPs. 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.

	5-Year Forecast		**20-Year Forecast**	
	Annual Growth Rate: Retail Sales (Billed MWh)	**Annual Growth Rate: Annual Peak (Peak Demand)**	**Annual Growth Rate: Retail Sales (Billed MWh)**	**Annual Growth Rate: Annual Peak (Peak Demand)**
2019 IRP (preliminary)	*1.3%*	*1.4%*	*1.0%*	*1.2%*
2017 IRP	1.1%	1.6%	0.9%	1.4%
2015 IRP	1.1%	1.5%	1.1%	1.4%

Idaho Power's 2017 IRP identifies its preferred resource portfolio and action plan. The IRP includes the completion of the Boardman-to-Hemingway 500-kV transmission line by 2026, the end of Idaho Power's participation in coal-fired operations at the North Valmy power plant units 1 and 2 in 2019 and 2025, respectively, and the early retirement of Jim Bridger units 1 and 2 in 2032 and 2028, respectively, with no other new resource needs prior to 2026. However, as noted in the 2017 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, 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.

Energy Efficiency and Demand Response Programs: Idaho Power’s energy efficiency and demand response portfolio is comprised of 23 programs. These energy efficiency programs target energy savings across the entire year, while the demand response programs target system demand reduction in the summer at times of peak loads. 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 and 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 electric heating, ventilation and cooling equipment, as well as energy efficient building techniques, 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 2018, Idaho Power’s energy efficiency programs reduced energy usage by approximately 173,000 MWh. For 2018, Idaho Power had a demand response available capacity of approximately 382 MW. In 2018, 2017, and 2016, Idaho Power expended approximately $44 million, $48 million, and $43 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 power cost adjustment mechanisms. Energy efficiency program expenditures funded through the riders are reported as an operating expense with an equal amount of revenues recorded in other revenues, resulting in no net impact on earnings.

Environmental, Social, and Governance Initiatives

IDACORP's and Idaho Power's boards of directors are responsible for the oversight of the companies' environmental, social, and governance (ESG) initiatives and are regularly informed of the goals, measures, and results of their ESG and sustainability programs. IDACORP and Idaho Power publicly released their inaugural sustainability report in May 2012 and have issued sustainability reports annually thereafter. IDACORP's and Idaho Power's ESG initiatives include establishing responsible management goals to balance shareholder return and the companies' impact on the environment (such as the sustainability benefits from the Boardman to Hemingway transmission project, which includes integrating renewable energy generation and deferring the need for development of additional fossil-fueled resources), operational excellence in providing reliable, fair priced, and clean energy, continuing various environmental stewardship programs along the Snake River, engaging and empowering Idaho Power's workforce (including succession planning at all levels, retirement planning education, and providing competitive pension benefits), promoting a culture of safety and inclusiveness for all employees, and building strong community partnerships for healthy economic development in Idaho Power's service area, among other things. The most current sustainability report is located on Idaho Power's website, together with other information on ESG issues relevant to Idaho Power. The sustainability reports and related website content are not incorporated by reference into this Annual Report on Form 10-K.

Reduction in Coal-Fired Generation: 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 an IPUC order in February 2014, 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 Valmy Plant as a coal-fired resource. In 2017 and 2018, the IPUC and OPUC approved settlement stipulations allowing accelerated depreciation and cost recovery for the Valmy Plant in connection with Idaho Power's plan to end its participation in the operation of unit 1 at the Valmy Plant by the end of 2019 and unit 2 by 2025. The plan to end Idaho Power's participation in operations of units 1 and 2 at the Valmy Plant was based primarily on the economics of operating the plant. The settlement stipulations are described in Part II, Item 7 - MD&A - "Regulatory Matters" in this report. Additionally, in light of the uncertainty resulting from pending environmental regulation and the substantial estimated cost of selective catalytic reduction equipment (SCR) installation, Idaho Power continues to assess whether to move forward with the installation of SCR on units 1 and 2 at the Jim Bridger power plant. The table above does not include costs associated with a SCR installation on units 1 and 2 at the Jim Bridger power plant.

Voluntary CO_2 Emissions Intensity Reduction Goal: Idaho Power is engaged in voluntary greenhouse gas emissions (GHG) emissions intensity reduction efforts. In 2013, IDACORP's and Idaho Power's boards of directors extended a goal they originally established in 2009, seeking to reduce the company-owned resource portfolio average carbon dioxide (CO_2) emissions intensity to 15-20 percent below 2005 levels of 1,194 lbs CO_2/MWh for the 2010-2017 cumulative period. Idaho Power has achieved and furthered the reduction goal several times, which now extends through 2020.

Idaho Power's estimated historic CO_2 emissions intensity from its generation facilities is as follows (in lbs CO_2/MWh):

	2018	2017	2016	2015	2014	2013	2012	2011	2010
Cumulative Emissions Intensity 2010-2018	869	896	934	944	945	929	867	864	1,066
Annual Average Emissions Intensity	647	632	858	944	1,015	1,129	874	681	1,066

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, particularly given the volume of existing and proposed regulations 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 AFUDC (in millions of dollars):

	2019	2020-2021
Capital expenditures:		
License compliance and relicensing efforts at hydroelectric facilities	$ 12	$ 35
Investments in equipment and facilities at thermal plants	4	22
Total capital expenditures	$ 16	$ 57
Operating expenses:		
Operating costs for environmental facilities - hydroelectric	$ 21	$ 42
Operating costs for environmental facilities - thermal	12	23
Total operations and maintenance	$ 33	$ 65

Idaho Power anticipates that finalization, implementation, or modification of a number of federal and state rulemakings and other proceedings addressing, among other things, greenhouse gases and endangered species could result in substantial changes in operating and compliance costs, but Idaho Power is unable to estimate those changes in costs given the uncertainty associated with existing and potential future regulations. Idaho Power expects that it would seek to recover increases in costs through the ratemaking process. Beyond 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 potential early plant retirements cannot be fully recovered in rates on a timely basis.

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. While IFS has not actively pursued new investment opportunities for some time, IFS does evaluate new investment opportunities. At December 31, 2018, the unamortized amount of IFS's portfolio was approximately $3 million ($146 million in gross tax credit investments, net of $143 million of accumulated amortization). IFS generated tax credits of $2.6 million in each year in 2018, 2017, and 2016. In 2018, 2017, and 2016, IFS received distributions related to fully-amortized affordable housing investments that reduced IDACORP's income tax expense by $0.3 million, $1.1 million, and $1.7 million, 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 44 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 $10 million in both 2018 and 2017 and $8 million in 2016.

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. There are no 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, 60

- 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
- Member of the Boards of Directors of IDACORP, Inc. and Idaho Power Company since September 2013

BRIAN R. BUCKHAM, 40
- Senior Vice President and General Counsel of IDACORP, Inc. and Idaho Power Company, February 2017 - present
- Vice President and General Counsel of IDACORP, Inc. and Idaho Power Company, April 2016 - February 2017
- In-house legal counsel of IDACORP, Inc. and Idaho Power Company, April 2010 - March 2016

JEFFREY S. GLENN, 51
- Vice President of Corporate Services and Chief Information Officer of Idaho Power Company, June 2018 - present
- Vice President of Information Technology and Chief Information Officer of Idaho Power Company, January 2016 - June 2018
- Vice President of Technology Operations of Verizon Digital Media Services, Inc. (a digital media content delivery network company), January 2014 - January 2016
- Vice President of Technology Operations of Edgecast Networks, Inc. (acquired by Verizon Digital Media Services, Inc. in 2014), January 2012 - January 2014

LISA A. GROW, 53
- Senior Vice President and Chief Operating Officer of Idaho Power Company, April 2016 - present
- Senior Vice President of Operations of Idaho Power Company, January 2016 - March 2016
- Senior Vice President - Power Supply of Idaho Power Company, October 2009 - December 2015

STEVEN R. KEEN, 58
- 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
- Senior Vice President - Finance and Treasurer of Idaho Power Company, January 2012 - December 2013
- Vice President - Finance and Treasurer of IDACORP, Inc., June 2010 - April 2014

JEFFREY L. MALMEN, 51
- Senior Vice President of Public Affairs of IDACORP, Inc. and Idaho Power Company, April 2016 - present
- Vice President of Public Affairs of IDACORP, Inc. and Idaho Power Company, October 2008 - March 2016

TESSIA PARK, 57
- 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

KEN W. PETERSEN, 55
- 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

N. VERN PORTER, 59
- Vice President of Transmission & Distribution Engineering and Construction and Chief Safety Officer, April 2016 - present
- Vice President of Customer Operations of Idaho Power Company, January 2016 - March 2016
- 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

ADAM RICHINS, 40
- Vice President of Customer Operations and Business Development of Idaho Power Company, March 2017 - present
- General Manager of Customer Operations, Engineering and Construction, January 2014 - February 2017
- In-house legal counsel of Idaho Power Company, November 2010 - January 2014

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, including without limitation, in Part II - Item 7 - "Management's Discussion and Analysis of Financial Condition and Results of Operations - Matters Impacting Future Results" in this report, and information in other reports the companies file with the SEC, should be considered carefully when making any investment decisions relating to IDACORP or Idaho Power.

State or federal regulators may not approve customer rates that provide timely or sufficient recovery of Idaho Power's costs or allow Idaho Power to earn a reasonable rate of return, which could cause IDACORP's and Idaho Power's financial condition and results of operations to be adversely affected.

The prices that the IPUC and OPUC authorize Idaho Power to charge customers for its retail services, and the tariff rate that the 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, liquidity, and financial condition. Idaho Power's ability to recover its costs and earn a reasonable rate of return can be affected by many regulatory factors, including the timing difference between when Idaho Power incurs costs and when Idaho Power recovers those costs in customers' rates (often called "regulatory lag" in the utility industry), and differences between the costs included 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, such as construction costs for new facilities or power lines, the costs of compliance with legislative and regulatory requirements, increased funding levels of a defined benefit pension plan, and the costs of damage from fires, weather-related events, and natural disasters. The IPUC, OPUC, and FERC may not allow Idaho Power to recover some or all of those costs on the basis that they find Idaho Power did not reasonably or prudently incur those costs or for other reasons. Ratemaking has generally been premised on estimates of historic costs based on a test year, so if a given year's actual costs are higher than historic costs, rates may not be sufficient to cover actual costs. While rate regulation is also premised on the assumption that rates established are fair, just, and reasonable, regulators have considerable discretion in applying this standard. Decisions are subject to judicial appeal, which could lead to further uncertainty in regulatory proceedings.

Economic, political, legislative, public policy, or regulatory pressures may lead stakeholders to seek rate reductions or refunds, limits on rate increases, or lower allowed rates of return on investments for Idaho Power. 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. The IPUC and OPUC may adopt different methods of calculating the allocation of the total utility costs in their respective jurisdictions, resulting in certain costs excluded in both states. In the past, Idaho Power has been denied recovery, or required to defer recovery pending the next general rate case, including denials or deferrals related to capital expenditures for long-term project expenses. Adverse outcomes in regulatory proceedings or significant regulatory lag may cause Idaho Power to record an impairment of its assets or otherwise adversely affect cash flows and earnings and result in lower credit ratings, reduced access to capital and higher financing costs, and reductions or delays in planned capital expenditures.

For additional information relating to Idaho Power's state and federal 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 or elimination, 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. The power cost adjustment mechanisms track Idaho Power's actual net power supply costs (primarily fuel and purchased power less wholesale energy sales) and compare these amounts to net power supply costs being recovered in retail rates. A majority of the differences between these two amounts is deferred for future recovery from, or refund to, customers through rates. Volatility in power supply costs continues to be significant, in large part due to fluctuations in hydroelectric generation conditions and high costs for the purchase of renewable energy under mandatory 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 a portion of Idaho Power's disincentive to invest in and support energy efficiency activities. This mechanism allows Idaho Power to charge Idaho 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. The power cost and fixed cost adjustment mechanisms are generally 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. Changes in the number of customers and customers' use of electricity are affected by a number of factors, such as population growth or decline in Idaho Power's service area, expansion or loss of service area, changes in customer needs and expectations, adoption rates of energy efficiency measures, customer-generated power such as from solar panels and gas-fired generators, demand-side management requirements, regulation or deregulation, and adverse economic conditions. An economic downturn or recession could also negatively impact customer use and reduce revenues and cash flows, thus adversely affecting results of operations. Many electric utilities, including Idaho Power, have experienced a decline in usage per customer, in part attributable to energy efficiency activities. State or federal regulations may be enacted to encourage or require mandatory energy conservation or technological advances that increase energy efficiency, which could further reduce usage per customer. Also, changing customer needs and expectations could lead to lower customer satisfaction, reduced loyalty, difficulty in obtaining rate increases, legislation to deregulate electric service, and customers seeking alternative sources of energy and electric service. If customers choose to generate their own energy, discontinue a portion or all service from Idaho Power, or replace electric power for heating with natural gas, demand for Idaho Power's energy may decline and adversely impact the affordability of its services for remaining customers. 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 1,063 kWh in 2009 to 945 kWh in 2018. 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 volume-based energy rates that are based on historical sales volume. Any undercollection of fixed costs would adversely impact revenues, earnings, and cash flows. 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 reduced revenues as well as 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 or population growth in the service area, 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, severe weather, and climate change. 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, 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, such as hot summers and cold winters. 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.

Climate change could also have significant physical effects in Idaho Power’s service area, such as increased frequency and severity of storms, lightning, droughts, heat waves, fires, floods, snow loading, and other extreme weather events, and impact Idaho Power’s ability to import power on transmission lines from other geographic areas. These extreme weather events and their associated impacts could damage transmission, distribution, and generation facilities, causing service interruptions and extended outages, increasing costs and other operating and maintenance expenses, and limiting Idaho Power's ability to meet customer energy demand. Sustained drought conditions or decreased snow pack due to higher temperatures are likely to decrease power generation from hydroelectric plants. Variations in hydroelectric generation that increase Idaho Power's reliance on market purchases may lead to more costly power supply sources for its customers and reduce benefits from selling surplus hydroelectric power in the wholesale market. The price of power in the wholesale energy markets tends to be higher during periods of high regional demand that tends to occur with weather extremes, which may cause Idaho Power to purchase power in the wholesale market during peak price periods, increasing power supply costs. The costs of repair and replacing infrastructure or liability for personal injury, loss of life, or property damage from utility equipment that fails as a result of significant weather and weather-related events, including fires, may not be covered in full by insurance. Costs incurred in connection with such events might also not be recovered through customer rates if the costs incurred are greater than those allowed for recovery by regulators. In addition, state and federal legislation and regulations have been proposed in recent years to limit the severity and impact of climate change, such as imposing mandatory reductions in greenhouse gas emissions, which could increase Idaho Power’s compliance costs. For additional information relating to legislation, regulations, and legal proceedings related to environmental matters, see Part II - Item 7 - "Management's Discussion and Analysis of Financial Condition and Results of Operations - Environmental Matters" in this report.

New advances in power generation, energy efficiency, or other technologies that impact the power utility industry could cause decreased customer energy demand and decreased revenues. Advances in technology and changes in customer demand and preferences in the electric utility industry have encouraged the development of new technologies for power generation, power storage, and energy efficiency. In particular, in recent years the net cost of solar generation has decreased significantly, and there are federal and state regulations, laws, and other incentives in place to help further reduce the net 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, which in turn could require changes in the way Idaho Power manages its distribution systems, and reduce the demand for and sale of energy. 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 use and demand. The introduction of new technologies could pose risks in the form of reduced sales and new business models for energy services. 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 investment in infrastructure, and reduce revenues, which would impact IDACORP's and Idaho Power's financial condition 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 require significant expenditures, or result in claims against the companies, and 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, including by nation states or nation state-sponsored groups. 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 frequent and sophisticated. 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 or distribution facilities, would be direct targets of, or indirect casualties of, an act of terror or cyber attack, including by nation states or nation state-sponsored groups (whether originating internally or externally) may affect Idaho Power's operations by limiting the ability to generate, purchase, or transmit power. Cyber threats and attacks can have cascading impacts that unfold with increasing speed across networks, information systems, and other technologies. Network, information systems, and technology-related events, including those caused by IDACORP or Idaho Power, such as process breakdowns, human error, security architecture or design vulnerabilities, or by third parties, such as computer hackings, cyber attacks, computer viruses, or other destructive or disruptive software, denial of service attacks, social engineering or other malicious activities, or any combination of the foregoing, could result in a degradation or disruption in the energy grid and the services of the companies. Physical or cyber attacks against key suppliers or service providers could have a similar effect on IDACORP and Idaho Power. Political, economic, social, or financial market instability or damage to or interference with Idaho Power’s operating assets, customers, or suppliers may result in business interruptions, lost revenue, higher commodity prices, disruption in fuel supplies, lower energy consumption, and unstable markets, particularly with respect to electricity and natural gas, and increased security, repair, or other costs, any of which may materially adversely affect Idaho Power in ways that cannot be predicted as of the date of this report. Any of these risks could materially affect the companies’ consolidated financial results.

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.

Idaho Power's operations require the continuous availability of information technology systems and network infrastructure, and in the normal course of business, Idaho Power or its vendors collect and store sensitive and confidential customer and employee information and proprietary information of Idaho Power. 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. Any security breaches, such as misappropriation, misuse, leakage, falsification or accidental release or loss of information maintained in IDACORP's and Idaho Power's information technology systems, including customer data, could result in violations of privacy and other laws, financial loss to Idaho Power or to its customers, customer dissatisfaction, damage to Idaho Power’s reputation, and significant litigation and penalty exposure, all of which could materially affect Idaho Power's financial condition and results of operations.

Capital expenditures for infrastructure, risks associated with permitting and 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;
- defaults by suppliers and contractors;
- equipment, engineering, and design failures;
- unexpected environmental and geological problems;
- the effects of adverse weather conditions;
- availability of financing;
- load forecasts;
- the ability to obtain and comply with permits and land use rights, and environmental constraints; and
- delays and costs associated with disputes and litigation with third parties.

The occurrence of any of these risks could cause Idaho Power to operate at reduced capacity levels, which in turn could reduce revenues, increase expenses, or cause Idaho Power to incur penalties. If Idaho Power is unable or unwilling to complete the permitting or 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 or if other resources become more economical, it may terminate those projects and, as alternatives, 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.

Changes in legislation, regulation, and government policy may have a material adverse effect on IDACORP’s and Idaho Power’s business in the future. Changes in, and uncertainty with respect to, federal, state, and local legislation, regulation, and government policy could significantly impact IDACORP’s and Idaho Power’s businesses and the electric utility industry. Specific legislative and regulatory proposals and recently enacted legislation that could have a material impact on IDACORP and Idaho Power include, but are not limited to, tax reform, utility regulation, infrastructure renewal programs, environmental regulation, and modifications to accounting and public company reporting requirements. Further, the proposals and new legislation could have an impact on the rate of growth of Idaho Power’s customers and their willingness to expand operations and increase electric service requirements. Laws, regulations, and policies relating to environmental compliance could change and require IDACORP and Idaho Power and their customers to modify their business strategy or affect their returns on investment by restricting activities and projects or subjecting them to increased compliance costs. IDACORP and Idaho Power are monitoring the implementation by federal, state, and local governmental authorities of various executive orders and are unable to predict whether and to what extent such actions will meaningfully change existing legislative and regulatory environments relevant to the companies, or if any such changes would have a net positive or negative impact on the companies. To the extent that such changes have a negative impact on the companies or Idaho Power’s customers, including as a result of related uncertainty, these changes may materially and adversely impact IDACORP’s and Idaho Power’s business, financial condition, results of operations, and cash flows.

Changes in income tax laws and regulations, or differing interpretation or enforcement of applicable laws by the U.S. 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 income taxes. Amounts of income 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, state regulatory mechanisms with income tax-related provisions (such as Idaho Power's May 2018 regulatory settlement stipulation with the IPUC), has significantly impacted IDACORP's and Idaho Power's results of operations. The outcome of potential future income tax proceedings, or the state public utility commissions' treatment of those 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 net income tax expense or benefit 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. In addition, Idaho Power uses the regulatory flow-through income tax accounting method as described in Note 1 - "Summary of Significant Accounting Policies" to the consolidated financial statements included in this report, and potential changes in income tax laws or interpretations may impact IDACORP's and Idaho Power's income taxes and reporting obligations differently than most other companies.

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 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. IDACORP's and Idaho Power's operations are subject to a number of federal, state, and local environmental statutes, rules, and regulations relating to air and water quality, natural resources, renewable energy, and health and safety. 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 regulations. However, it is possible that federal, state and local authorities could attempt to enforce 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. Compliance with environmental regulations can significantly increase capital spending, operating costs, and plant outages, and can negatively affect the affordability of Idaho Power's services for customers. Idaho Power cannot predict with certainty the amount and timing of all future expenditures necessary to comply with these environmental laws and regulations, although Idaho Power expects the expenditures will 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 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.

The current presidential administration has issued a number of executive orders related to environmental matters designed to ease environmental regulation that the federal agencies are still implementing. However, the outcome of the Environmental Protection Agency's and other federal agencies' review of regulations covered by the executive orders is difficult to predict. Moreover, the executive orders and any resulting federal regulations could be affected by Congressional action and challenged in court. Further, state and local governmental authorities could choose to replace the federal regulations or bolster environmental compliance and enforcement efforts at the local level. Accordingly, Idaho Power may not realize any benefit from changes to federal environmental regulations, if any, resulting from the executive orders and, as of the date of this report, cannot predict whether and to what extent the orders and resulting changes to regulations could affect its operations and environmental-related expenditures.

In addition, some environmental regulations are currently subject to litigation and not yet final. As a result of this uncertainty, approaches to comply with the regulations, including available control technologies or other allowed compliance measures, are unpredictable and Idaho Power cannot foresee the potential impacts these regulations would have on Idaho Power's operations or financial condition. Idaho Power is not guaranteed timely or full recovery through customer rates or insurance of costs associated with environmental regulations, environmental compliance, plant closures, or clean-up of contamination. 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 2017 and 2018, 65 percent of Idaho Power's electric power generation was from hydroelectric facilities. Due to Idaho Power’s heavy reliance on hydroelectric generation, factors such as precipitation and snowpack, 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 wholesale energy 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 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. Another significant issue related to the relicensing effort involves a dispute between the states of Idaho and Oregon regarding whether to reintroduce or establish spawning populations of fish species into Idaho waters. In December 2018, the states of Idaho and Oregon, along with Idaho Power, reached a proposed settlement on this matter, requiring Idaho Power to reintroduce certain fish species and fund-related research. Idaho Power cannot predict the outcome of these proceedings, 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 volatile and influenced by factors impacting supply and demand such as weather conditions, the adequacy and type of generating capacity, 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 or unforeseeable events that inhibit their ability to deliver natural gas or coal. Disruptions in transportation of fuel and 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.

If the assumptions underlying coal mine reclamation at Bridger Coal Company and related forecast trust fund growth are materially inaccurate, Idaho Power’s costs could be greater than anticipated or be incurred sooner than anticipated. Bridger Coal Company, a subsidiary of Idaho Power, uses both surface and underground methods to mine coal to be used for power generation at the Jim Bridger power plant. The federal Surface Mining Control and Reclamation Act and state laws and regulations establish operational, reclamation, bonding, and closure obligations and standards for mining of coal. Bridger Coal Company’s estimate of reclamation liability and bonding obligations is reviewed periodically by Idaho Power’s management committee, audit committee of the board of directors, external and internal auditors, and by government regulators. Idaho Power funds a trust to cover such projected mine reclamation costs. The trust funds are invested in debt and equity securities and poor performance of these investments would reduce the amount of funds available for their intended purpose, which could require Idaho Power to make additional cash contributions. If actual costs related to those obligations exceed estimates, government regulations relating to those obligations change significantly or unexpected cash funding obligations are required, IDACORP’s and Idaho Power’s results of operations and financial condition could be adversely affected.

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 or attrition, accidents and workforce safety matters, release of hazardous or toxic substances into the air, water, or ground, wildfires, 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, liability to third parties, 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. Further, the transmission system in Idaho Power's service area is constrained, limiting the ability to transmit electric energy within the service area and access electric energy from outside the service area 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, and the inability to access lower cost sources of electric energy. Idaho Power also enters into agreements with third party contractors to perform work on its generation, transmission, and distribution facilities, and may in some circumstances retain liability for the quality and completion of those contractors’ work, potentially subjecting Idaho Power to penalties, liability for personal injury, loss of life, or property damage, or enforcement actions or liability if a contractor violates applicable laws, rules, regulations, or orders.

Accidents, terrorist acts, electrical contacts, fires, explosions, catastrophic failures, general system damage or dysfunction, uncontrolled release of water from hydroelectric dams, and other unplanned events related to Idaho Power's infrastructure would increase repair costs and may expose Idaho Power to liability for personal injury, loss of life, and property damage. Fires alleged to have been caused by Idaho Power's transmission, distribution, or generation infrastructure, or that allegedly result from Idaho Power’s or its contractors’ operating or maintenance practices, could also expose Idaho Power to claims for fire suppression and clean-up costs, evacuation costs, fines and penalties, and liability for economic damages, personal injury, loss of life, and property damage, whether based on claims of negligence, trespass, or otherwise. The risk of wildfires is exacerbated in forested areas where beetle infestations have caused a significant increase in the quantity of standing dead and dying timber, increasing the risk that such trees may fall from either inside or outside our right-of-way into a powerline igniting a fire and increasing the magnitude of fires. A significant number of urban-wildland interfaces in and near Idaho Power's service area, and commonly hot, dry summer conditions, increase the likelihood and magnitude of damages that may be caused by fires burning into or allegedly originating from utility equipment. Idaho Power maintains insurance coverage for such operating and event risks, but insurance coverage is subject to the terms and limitations of the available policies and may not be sufficient in amount to cover Idaho Power’s ultimate liability. Coverage limits within wildfire insurance policies could result in material self-insured costs in the event there are fires that are deemed to be separate occurrences covered by self-insured retention amounts under the terms of Idaho Power’s insurance policies. Idaho Power or its contractors and customers could also experience coverage reductions and increased wildfire insurance costs in future years. Idaho Power may be unable to fully recover costs in excess of insurance through customer rates or regulatory mechanisms and, even if such recovery is possible, it could take several years to collect. If the amount of insurance is insufficient or otherwise unavailable, and if Idaho Power is unable to fully recover in rates the costs of uninsured losses, IDACORP’s and Idaho Power’s financial condition, results of operations, or cash flows could be materially affected.

Volatility or disruptions 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 and ability to execute on their strategic plans. 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 ability and obligation of the participating banks to make those loans and issue letters of credit is subject to specified conditions and volatility or disruptions in the financial markets could affect the companies' ability to obtain debt financing or draw upon or renew existing credit facilities. 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. 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. The companies must also make specified representations in connection with request for loans and it is possible that they may be unable to do so at the time of such request, which would limit or eliminate the obligation of the banks to provide loans. Failure to maintain these representations and 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 limit their ability to pursue certain projects and 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, reduce the pool of potential lenders, increase borrowing costs under existing credit facilities, limit access to the commercial paper market, 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. If access to capital were to become significantly constrained or costs of capital increased significantly due to lowered credit ratings, prevailing industry conditions, regulatory constraints, the volatility of the capital markets or other factors, IDACORP's and Idaho Power's financial condition and results of operations could be adversely affected.

Changes in the method for determining LIBOR and the potential replacement of LIBOR may affect our credit facilities and the interest rates on such borrowings. LIBOR, the London interbank offered rate, is the basic rate of interest used in lending between banks on the London interbank market and is widely used as a reference for setting the interest rate on loans globally. The interest rates for any borrowings under IDACORP and Idaho Power’s credit 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. In July 2017, the United Kingdom's Financial Conduct Authority, which regulates LIBOR, announced that it intends to phase out LIBOR by the end of 2021. It is unclear if at that time LIBOR will cease to exist or if new methods of calculating LIBOR will be established such that it continues to exist after 2021. If the method for calculation of LIBOR changes, if LIBOR is no longer available, or if lenders have increased costs due to changes in LIBOR, IDACORP and Idaho Power may suffer from potential increases in interest rates on any borrowings. Further, IDACORP and Idaho Power may need to renegotiate their credit facilities that utilize LIBOR as a factor in determining the interest rate to replace LIBOR with the new standard that is established.

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 buy and sell power, natural gas, and transmission service, 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 purchase or sale, 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. 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 that Idaho Power may not be able to collect in customer rates. The FERC may take action to limit volatility in the energy market by imposing price limits or other market restrictions to control market-based rate sales, which could adversely affect the companies' financial results. As a result, risk management actions, or the failure or inability to manage commodity availability and price and counterparty risk, may adversely affect IDACORP's and Idaho Power's financial condition and results of operations. Further, the bankruptcy or insolvency of a counterparty to commodity or other transactions could impair Idaho Power's ability to collect amounts receivable from those counterparties, potentially including the ability to collect or retain collateral posted by a counterparty. In January 2019, Pacific Gas & Electric Company and PG&E Corporation, its parent entity (collectively, PG&E), filed voluntary bankruptcy petitions under Chapter 11 of the U.S. Bankruptcy Code. Idaho Power does not have any direct power, gas, or derivative transactions with PG&E. However, both Idaho Power and PG&E are participants in the Western EIM and engage in indirect power purchase and sale transactions in connection with that participation. The Western EIM has collateral posting requirements based on established credit criteria, but there is no assurance the collateral will be sufficient to cover obligations that PG&E may owe other participants in the Western EIM. Also, PG&E purchases the output of power from small hydroelectric facilities located in California, in which Ida-West is a 50% co-owner. If PG&E is unable to perform on its obligations under its arrangements with Ida-West's joint venture, IDACORP does not believe the impact would be material to its financial condition nor results of operations. However, a bankruptcy filing of the magnitude of PG&E's filing in 2019 could have a ripple effect on various Idaho Power counterparties in the power, gas, and derivative markets if those counterparties experience ancillary liquidity issues, and could generally result in a decline in the ability of Idaho Power's counterparties to perform on their obligations.

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 and security standards issued by the FERC and other regulators. 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, security, 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 exceed $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 also 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 and impacts Idaho Power's ability to invest in additional generation. Increases in customer rates could make self-generation more financially attractive for customers, which could result in reduced net load and shifts in customer costs. 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 or the failure to maintain sustained growth in pension investments over time could increase Idaho Power’s plan costs and funding requirements related to the plans. As benefit costs continue to rise, there is no assurance that the state public utility commissions will continue to allow recovery. 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 investment 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 12 - "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, tax obligations, 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 7 - "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, weather conditions, and other events and conditions 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, engineering and design personnel, 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 2019 and in the near-term. At December 31, 2018, approximately 22 percent of Idaho Power's employees were eligible for regular or early retirement under Idaho Power's defined benefit pension plan. 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 failure to hire 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 management is often unable to predict the outcome of such matters; resulting liabilities could exceed amounts currently reserved or insured against with respect to such matter. The legal costs and final resolution of matters in which IDACORP or Idaho Power are involved could have reputational impact and a short- or long-term 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.

Changes in accounting standards or rules may impact IDACORP's and Idaho Power's financial results and disclosures. The Financial Accounting Standards Board (FASB) and the SEC have made and may continue to 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. IDACORP and Idaho Power do not have any control over the impact these changes may have on their financial conditions or results of operations nor the timing of such changes. Idaho Power meets conditions under GAAP 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, 2018, the system also includes approximately 4,816 pole-miles of high-voltage transmission lines, 24 step-up transmission substations located at power plants, 21 transmission substations, 9 switching stations, 32 mixed-use transmission and distribution substations, 183 energized distribution substations (excluding mobile substations and dispatch centers), and approximately 27,569 pole-miles of distribution lines.

Idaho Power holds Federal Energy Regulatory Commission (FERC) licenses for all of its hydroelectric projects that are subject to federal licensing. Relicensing of Idaho Power’s hydroelectric projects is discussed in Part II - Item 7 - MD&A – "Regulatory Matters – Relicensing of Hydroelectric Projects” in this report.

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	11,500	2034
CJ Strike	82,800	2034
Upper Malad - Lower Malad	21,770	2035
Brownlee - Oxbow - Hells Canyon (Hells Canyon Complex)	1,235,600	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	9,300	
Total Hydroelectric	1,774,745	
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	3,660,098	

(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 one-third for Jim Bridger, 50 percent for North 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 305,741 square feet of owned office space. Excluding Idaho Power's power generation facilities and substations, Idaho Power owns an additional 1,113,631 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 Federal Power Act (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 Bridger Coal Company (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 nameplate capacity of 44 MW. These plants are located in Idaho and California.

ITEM 3. LEGAL PROCEEDINGS

Refer to Note 11 – “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

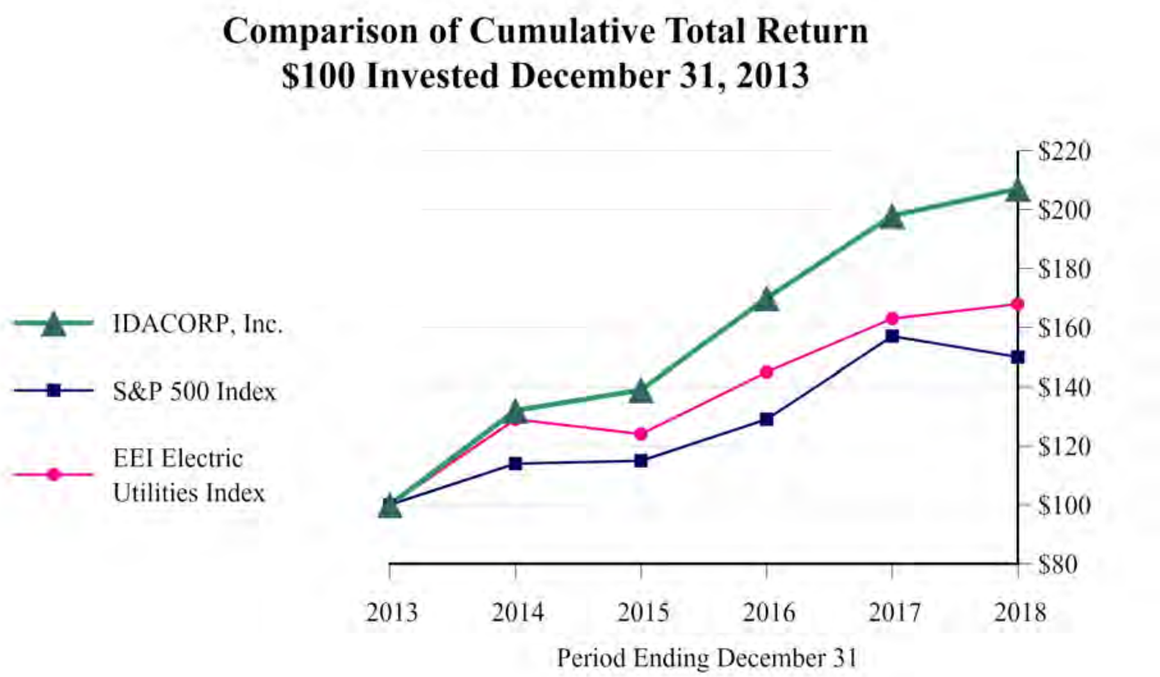
IDACORP's common stock, without par value, is traded on the New York Stock Exchange (NYSE) under the trading symbol "IDA". On February 15, 2019, there were 9,006 holders of record of IDACORP common stock. The outstanding shares of Idaho Power's common stock, $2.50 par value, are held by IDACORP and are not traded. IDACORP became the holding company of Idaho Power on October 1, 1998.

For information regarding IDACORP's dividend policy, see Part II - Item 7 - MD&A - "Liquidity and Capital Resources - Dividends" in this report. For information relating to restrictions on dividends see, Note 7 - "Common Stock" to the consolidated financial statements included in this report.

IDACORP did not repurchase any shares of its common stock during the fourth quarter of 2018.

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, 2013, with beginning-of-period weighting of the peer group indices (based on market capitalization) and monthly compounding of returns.



Source: Bloomberg and EEI

	2013	2014	2015	2016	2017	2018
IDACORP	$ 100.00	$ 131.78	$ 139.49	$ 169.92	$ 197.83	$ 206.86
S&P 500	100.00	113.68	115.25	129.02	157.17	150.27
EEI Electric Utilities Index	100.00	128.91	123.88	145.48	162.53	168.49

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)

	2018	2017	2016	2015	2014
Operating revenues	$1,370,752	$1,349,486	$1,262,020	$1,270,289	$1,282,524
Operating income(1)	296,922	315,545	283,582	297,048	267,194
Net income attributable to IDACORP, Inc.	226,801	212,419	198,288	194,679	193,480
Diluted earnings per share	4.49	4.21	3.94	3.87	3.85
Dividends declared per share	2.40	2.24	2.08	1.92	1.76
Financial Condition:					
Total assets(2)	$6,382,754	$6,045,405	$6,289,897	$6,023,314	$5,701,037
Long-term debt (including current portion)(2)	$1,834,788	$1,746,123	$1,745,678	$1,726,474	$1,599,686
Financial Statistics:					
Times interest charges earned:					
Before tax(3)	3.55	3.82	3.54	3.61	3.38
After tax(4)	3.36	3.30	3.15	3.12	3.19
Book value per share(5)	$ 47.04	$ 44.68	$ 42.74	$ 40.88	$ 38.85
Market-to-book ratio(6)	198%	204%	188%	166%	170%
Payout ratio(7)	53%	53%	53%	50%	46%
Return on year-end common equity(8)	9.6%	9.4%	9.2%	9.5%	9.9%

(1) Operating income in 2018-2014 reflects IDACORP's 2018 adoption of Accounting Standards Update (ASU) 2017-07. IDACORP retrospectively adjusted prior periods to reflect the disaggregation of service cost from other components of net periodic benefit cost. The non-service cost components of net periodic benefit cost were reclassified from "Other operations and maintenance" and "Other" operating expenses to "Other Expense, Net" on the consolidated statements of income to conform to current period presentation.

(2) Amounts in 2014 were adjusted to reflect IDACORP's 2015 adoption of ASU 2015-03, which required debt issuance costs be reported as reductions of long-term debt rather than as long-term assets on the consolidated balance sheets.

The financial statistics listed above are calculated in the following manner:

(3) The sum of "Interest on long-term debt," "Other interest" expense, and "Income before income taxes" divided by the sum of "Interest on long-term debt" and "Other interest" expense on the consolidated statements of income.

(4) The sum of "Interest on long-term debt," "Other interest" expense, and "Net income attributable to IDACORP, Inc." divided by the sum of "Interest on long-term debt" and "Other interest" expense on the consolidated statements of income.

(5) "Total IDACORP, Inc. shareholders' equity" on the consolidated balance sheets at the end of the year divided by shares outstanding at the end of the year.

(6) 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 (5) above.

(7) Dividends paid per common share divided by diluted earnings per share.

(8) "Net income attributable to IDACORP, Inc." on the consolidated income statements divided by "Total IDACORP, Inc. shareholders' equity" on the consolidated balance sheets 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 and its subsidiaries and Idaho Power and its subsidiary 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.

INTRODUCTION

IDACORP is a holding company 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 Utilities 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 areas, as well as from the wholesale sale and transmission of electricity.

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 notable subsidiaries include IDACORP Financial Services, Inc. (IFS), an investor in affordable housing and other real estate investments; and 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).

EXECUTIVE OVERVIEW

IDACORP is committed to its focus on competitive total returns and generating long-term value for shareholders. IDACORP’s business strategy emphasizes Idaho Power as IDACORP’s core business, since Idaho Power’s regulated electric utility operations are the primary driver of IDACORP’s operating results. This strategy is described in Part I, Item 1 - "Business - Business Strategy" of this report. Examples of IDACORP's and Idaho Power's achievements and recognitions during 2018 include:

- IDACORP achieved net income growth for an eleventh consecutive year;
- IDACORP provided a 14 percent cumulative annual total shareholder return over the past three years, including share price appreciation and dividends paid, ranking in the 63rd percentile among peer companies in the Edison Electric Institute (EEI) Electric Utilities Index;
- IDACORP received its second EEI Electric Utilities Index award in the past three years, for the best total shareholder return performance among small cap utilities (market capitalization of less than $5 billion) over the past five years, measured as of September 30, 2018;
- IDACORP increased its quarterly common stock dividend from $0.59 per share to $0.63 per share, as a part of a 110 percent increase in quarterly dividends approved over the last seven years under the company's objective to pay dividends at the upper end of the range of 50 percent to 60 percent of sustainable earnings;
- Idaho Power's customer count grew 2.3 percent in 2018;
- Idaho Power ranked second in J.D. Power's Electric Utility Residential Customer Satisfaction Study in its West Region Midsize segment for the second year in a row;
- Idaho Power reached milestones on key transmission projects as the U.S. Forest Service issued a record of decision on the siting of the Boardman-to-Hemingway 500-kV project and the U.S. Bureau of Land Management (BLM) issued a record of decision for the remaining transmission line segments of the Gateway West 500-kV transmission project;
- Idaho Power achieved its carbon dioxide (CO_2) emissions intensity reduction goal; and
- Idaho Power reached several constructive regulatory settlements that were approved by the IPUC and OPUC related to recent income tax reform, the indefinite extension, with modifications, of the current earnings support and revenue sharing mechanism, the prudence of certain Hells Canyon Complex (HCC) relicensing costs, and the treatment of costs incurred to join the energy imbalance market implemented in the western United States (Western EIM).

Summary of 2018 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, 2018, 2017, and 2016 (in thousands, except earnings per share amounts):

	Year Ended December 31,		
	2018	**2017**	**2016**
Idaho Power net income	$ 222,334	$ 206,347	$ 189,242
Net income attributable to IDACORP, Inc.	$ 226,801	$ 212,419	$ 198,288
Average outstanding shares – diluted (000's)	50,510	50,424	50,373
IDACORP, Inc. earnings per diluted share	$ 4.49	$ 4.21	$ 3.94

The table below provides a reconciliation of net income attributable to IDACORP for the year ended December 31, 2018, from the year ended December 31, 2017 (items are in millions and are before tax unless otherwise noted):

Net income attributable to IDACORP, Inc. - December 31, 2017		**$ 212.4**
Increase (decrease) in Idaho Power net income:		
Customer growth, net of associated power supply costs and power cost adjustment mechanisms	10.3	
Usage per retail customer, net of associated power supply costs and power cost adjustment mechanisms	(9.4)	
Idaho fixed cost adjustment (FCA) revenues	17.7	
Retail revenues per MWh, net of associated power supply costs and power cost adjustment mechanisms	(26.9)	
Transmission wheeling and other revenues	16.1	
Non-cash amortization of regulatory deferrals (related to tax reform)	(4.0)	
Other operations and maintenance (O&M) expenses (excluding non-cash amortization of regulatory deferrals)	(13.8)	
Other changes in operating revenues and expenses, net	(3.6)	
Decrease in Idaho Power operating income prior to sharing mechanism	(13.6)	
Decrease in revenues as a result of sharing mechanism	(5.0)	
Decrease in Idaho Power operating income	(18.6)	
Earnings of unconsolidated equity-method investments	1.4	
Non-operating income and expenses, net	0.3	
Decrease in income tax expense from remeasurement of deferred taxes and make-whole premium for early bond redemption	9.0	
Income tax expense (excluding remeasurement of deferred taxes and make-whole premium for early bond redemption)	23.9	
Total increase in Idaho Power net income		16.0
Other IDACORP changes (net of tax)		(1.6)
Net income attributable to IDACORP, Inc. - December 31, 2018		**$ 226.8**

IDACORP's net income increased $14.4 million for 2018 compared with 2017, primarily due to higher net income at Idaho Power. Customer growth added $10.3 million to Idaho Power's operating income compared with 2017. Sales volumes on a per-customer basis decreased operating income by $9.4 million in 2018 compared with 2017. A decrease in sales volumes to residential customers was partially offset by an increase in usage per irrigation customer. Milder temperatures in 2018 compared with 2017 caused residential customers to use 6 percent less electricity per customer, mostly for cooling and heating purposes, while decreased precipitation led agricultural irrigation customers to use 9 percent more electricity per customer to operate irrigation pumps. However, due mostly to the lower usage by Idaho residential customers, the FCA mechanism added $17.7 million to operating income during 2018 compared with 2017.

The net decrease in retail revenues per MWh reduced operating income by $26.9 million in 2018 compared with 2017. The settlement stipulations approved by the IPUC and OPUC during the second quarter of 2018 relating to recent income tax reform reduced revenues by approximately $22 million in 2018. The timing of the revenue reductions may not align with decreases in income tax expense in any given period due to the method and timing of customer rate reductions provided for in the settlement stipulations, the nature and timing of income tax accruals, discrete items, and other items discussed in more detail in the "Income Tax Reform" section below. Also, a change in customer sales mix reduced the retail revenues per MWh as volumes sold to residential customers made up a smaller portion of the customer sales mix.

During 2018, Idaho Power benefited from a $16.1 million increase in transmission wheeling and other revenues, compared with 2017. This change was largely due to a 37 percent increase in the Open Access Transmission Tariff (OATT) rate in October 2017, partially offset by a 10 percent decrease in the OATT rate in October 2018 and, to a lesser extent, an increase in wheeling volumes.

Other O&M expenses included $4.0 million of non-cash amortization expense of regulatory deferrals that would otherwise be a future liability of Idaho customers, as provided by the settlement stipulation approved by the IPUC related to income tax reform. Excluding the non-cash amortization of regulatory deferrals, other O&M expenses were $13.8 million higher in 2018 compared with 2017. In 2018, compared with 2017, higher maintenance service costs led to a $4.2 million increase in transmission and distribution asset maintenance expenses, and higher variable employee-related costs led to an $8.4 million increase in labor and benefit expenses.

In 2018, Idaho Power recorded $5.0 million as a provision against current revenues to be refunded to customers through a future rate reduction, through the Idaho-jurisdiction power cost adjustment (PCA) mechanism pursuant to a settlement stipulation with the IPUC as described in "Regulation of Rates and Cost Recovery" below.

Idaho Power's $5.7 million remeasurement of deferred taxes resulting from the federal and Idaho income tax rate change (discussed in further detail below) on the adjustment of temporary differences as a result of IDACORP’s 2017 consolidated income tax return filings and the $1.3 million flow-through benefit of a tax deductible make-whole premium that Idaho Power paid in connection with the early redemption of long-term debt in April 2018 decreased Idaho Power's income tax expense by $7.0 million in 2018. Idaho Power recorded $2.0 million of income tax expense in 2017 for the initial remeasurement of deferred taxes resulting from the federal and Idaho income tax rate change. Excluding these items, Idaho Power income tax expense was $23.9 million lower during 2018 compared with 2017, due mostly to the lower federal and state statutory income tax rates resulting from income tax reform.

2018 Initiatives and Strategy

IDACORP’s strategy is focused on four areas: growing to enhance financial strength, improving Idaho Power's core business, enhancing Idaho Power’s brand, and focusing on safety and employee engagement. IDACORP's board of directors has reviewed and affirmed IDACORP’s long-term strategy. In executing on these four strategic focus areas, IDACORP seeks to balance the interests of shareowners, Idaho Power customers, employees, and other stakeholders. Idaho Power is working to continue to provide safe, fair-priced, reliable service to its customers from a diversified source of generation resources, with a continued commitment to strong, sustainable financial results. For more information on the business strategy of the companies, see Part I, Item 1 – “Business - Business Strategy” in this report.

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 below 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. Idaho Power focuses on timely recovery of its costs through filings with its regulators, working to put in place innovative regulatory mechanisms, and on the prudent management of expenses and investments. Idaho Power has regulatory settlement stipulations in Idaho that include provisions for the accelerated amortization of certain tax credits to help achieve a minimum 9.5 percent (9.4 percent after 2019) return on year-end equity in the Idaho jurisdiction (Idaho ROE). The settlement stipulations also provide for the potential sharing between Idaho Power and customers of Idaho-jurisdictional earnings in excess of specified levels of Idaho ROE. The settlement stipulations provide for modifications of certain terms and the indefinite extension of the mechanism beyond the original termination date of December 31, 2019. The specific terms of these settlement stipulations are described in "Regulatory Matters" in this MD&A and in Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report. During

2019, Idaho Power will continue to assess the need to file a general rate case to reset base rates, but does not anticipate filing a rate case in the next twelve months.

- ***Income Tax Reform:*** In December 2017, the Tax Cuts and Jobs Act was signed into law, which lowered the corporate federal income tax rate from 35 percent to 21 percent and modified or eliminated certain federal income tax deductions for corporations (Tax Cuts and Jobs Act). The majority of the changes, including the rate reduction, became effective on January 1, 2018. In March 2018, Idaho House Bill 463 was signed into law reducing the Idaho state corporate income tax rate from 7.4 percent to 6.925 percent. In May 2018, the IPUC issued an order approving a settlement stipulation related to these changes in income taxes (May 2018 Idaho Tax Reform Settlement Stipulation). Beginning June 1, 2018, the settlement stipulation provided an annual (a) $18.7 million reduction to Idaho customer base rates and (b) $7.4 million for the amortization of regulatory deferrals that would otherwise be a future liability recoverable from Idaho customers. Additionally, a one-time benefit of a $7.8 million rate reduction is being provided to Idaho customers through the PCA mechanism during the period from June 2018 through May 2019, for the income tax reform benefits accrued from January 2018 to May 2018 and for amounts included in Idaho Power's transmission revenues. The May 2018 Idaho Tax Reform Settlement Stipulation was designed to return to Idaho customers their share of the estimated annual pro forma tax expense reductions resulting from income tax reform, based on the full-year 2017 as required by the IPUC. Idaho Power's financial results from 2018 forward will be affected by any differences between annual income tax expense and the pro forma 2017 income tax expense used in the settlement until incorporated into a future rate proceeding or rate case. Refer to "Regulatory Matters" in this MD&A for more information on the related regulatory proceedings.

- ***Economic Conditions and Loads:*** Economic conditions impact consumer demand for energy, revenues, collectability of accounts, the volume of wholesale energy 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 2018, Idaho Power's customer count grew by 2.3 percent, and employment in Idaho Power's service area grew by approximately 2.2 percent based on Idaho Department of Labor preliminary December 2018 data. Idaho Power expects its number of customers to continue to increase in the foreseeable future. Idaho Power has in recent years supported State of Idaho-coordinated efforts to promote economic development with an emphasis on attracting industrial and commercial customers to its service area.

  In August 2018, Idaho Power began preparing its 2019 Integrated Resource Plan (IRP), Idaho Power's long-term forecast of loads and resources. For more information on the 2019 IRP, including the preliminary load forecast assumptions Idaho Power expects to use in its 2019 IRP, refer to "Resource Planning" in Item 1 - "Business" in this Form 10-K.

- ***Weather Conditions:*** Weather and agricultural growing conditions have a significant impact on Idaho Power's energy 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 extent 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. Much of the adverse or favorable impact of weather on sales of energy to Idaho residential and small commercial customers is mitigated through the FCA mechanism, which is described in Note 3 - "Regulatory Matters" to the consolidated financial statements in this report.

  Further, as Idaho Power's hydroelectric facilities comprise approximately 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 wholesale energy 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 mechanisms.

- ***Rate Base Growth and Infrastructure Investment:*** As noted above, the rates established by the IPUC and OPUC are determined with the intent 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 and certain other assets, 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 in an effort to maintain system reliability, ensure an adequate supply of electricity, and to provide service to new customers, including major ongoing transmission projects such as the Boardman-to-Hemingway and Gateway West projects. Idaho Power's existing hydroelectric and thermal generation facilities also require continuing upgrades and equipment replacement, and the company is undertaking a significant relicensing effort for the HCC, its largest hydroelectric generation resource. Idaho Power intends to pursue timely inclusion of any significant completed capital projects into rate base as part of a future general rate case or other appropriate regulatory proceeding.

- ***Mitigation of Impact of Fuel and Purchased Power Expense:*** In addition to hydroelectric generation, Idaho Power relies heavily on natural gas and coal to fuel its generation facilities and power purchases in the wholesale markets. Fuel costs are impacted by electricity sales volumes, the terms and conditions 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 decreased operation of coal-fired plants. Purchased power costs are impacted by the terms and conditions 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. The Idaho and Oregon power cost adjustment mechanisms mitigate in large part the potential adverse impacts of fluctuations in power supply costs to Idaho Power.

- ***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, the North American Electric Reliability Corporation, and Western Electricity Coordinating Council. Compliance with these requirements directly influences Idaho Power's operating environment and affects Idaho Power's operating costs. Recently, energy industry regulators have issued substantial penalties for utilities alleged to have violated reliability and critical infrastructure protection requirements. Moreover, environmental laws and regulations, in particular, may increase the cost of operating generation plants, including Idaho Power's coal-fired 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. Idaho Power expects to spend a considerable amount on environmental compliance and controls in the next decade, and due to economic factors in part associated with the costs of compliance with environmental regulation, has accelerated the retirement dates of certain of its coal-fired power plants.

- ***Water Management and Relicensing of the Hells Canyon Hydroelectric Project:*** 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 are expected to continue to be substantial. Idaho Power cannot currently determine the terms of, and costs associated with, any resulting long-term license.

RESULTS OF OPERATIONS

This section of 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 2018 are compared with 2017 and the results for 2017 are compared with 2016.

The table below presents Idaho Power's energy sales and supply (in thousands of MWh) for the last three years.

	Year Ended December 31,		
	2018	**2017**	**2016**
Retail energy sales	14,587	14,571	14,196
Wholesale energy sales	2,246	1,934	742
Bundled energy sales	617	202	444
Total energy sales	17,450	16,707	15,382
Hydroelectric generation	8,682	8,900	6,408
Coal generation	3,274	3,284	4,045
Natural gas and other generation	1,408	1,504	1,722
Total system generation	13,364	13,688	12,175
Purchased power	5,431	4,242	4,337
Line losses	(1,345)	(1,223)	(1,130)
Total energy supply	17,450	16,707	15,382

For purposes of illustration, Boise, Idaho, weather-related information for the last three years is presented in the table that follows.

	Year Ended December 31,			
	2018	**2017**	**2016**	**Normal**[(2)]
Heating degree-days[(1)]	4,984	5,655	4,807	5,514
Cooling degree-days[(1)]	1,116	1,341	1,001	942
Precipitation (inches)	10.6	15.4	8.7	11.3

(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 above 65 degrees is counted as one cooling degree-day, and each degree 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.

(2) Normal heating degree-days and cooling degree-days elements are, by convention, the arithmetic mean of the elements computed over 30 consecutive years. The annual normal amounts are the sum of the 12 monthly normal amounts. These normal amounts are computed by the National Oceanic and Atmospheric Administration.

Sales Volume and Generation: In 2018, retail sales volumes were relatively flat compared with those of the prior year. Customer growth increased sales volumes during 2018 compared with 2017, with the number of Idaho Power's customers growing by 2.3 percent. During 2018, usage per irrigation customer was approximately 9 percent higher compared with 2017. Precipitation in the Idaho Power service area during 2018 was significantly less than in 2017, which increased usage by irrigation customers in 2018. Usage per residential customer was approximately 6 percent lower in 2018 compared with 2017. The decrease in residential usage was primarily due to milder weather during 2018 compared with 2017, which decreased the use of electricity for heating and cooling purposes. Cooling degree-days in Boise, Idaho were 17 percent lower during 2018 compared with 2017, but 18 percent above normal. Heating degree-days in Boise, Idaho were 12 percent lower during 2018 compared with 2017, and 10 percent below normal. Also, bundled energy sales (electric power combined with renewable energy certificates) volumes increased during 2018 compared with 2017. The solar generation projects under PURPA contracts that were initiated in 2017 generated an increased number of renewable energy credits to sell bundled with electricity.

Total system generation decreased 2 percent during 2018 compared with 2017. Hydroelectric generation decreased 2 percent during 2018 compared with 2017, but comprised 65 percent of Idaho Power's total system generation during both 2018 and 2017. In 2018, purchased power increased 28 percent compared with 2017 due to an increase in power purchased from generation projects under mandatory PURPA contracts and an increase in other purchased power resulting from favorable wholesale gas and electricity market conditions and, to a lesser extent, transactions in the Western EIM, which commenced in

April 2018. The availability of hydroelectric generation and an increase in purchased power during 2018 reduced thermal generation compared with 2017.

Wholesale energy sales volumes increased 312 thousand MWh, or 16 percent, during 2018 compared with 2017, due primarily to an increase in purchased power, both in market purchases and in purchases under PURPA contracts, resulting in increased energy available for wholesale energy sales. However, the high purchase price of power under federally mandated PURPA purchases is often in excess of the price at which Idaho Power sells the power in the wholesale energy markets.

The financial impacts of fluctuations in wholesale energy sales, purchased power, fuel expense, and other power supply-related expenses are addressed in Idaho Power's Idaho and Oregon power cost adjustment mechanisms, which are described below in "Power Cost Adjustment Mechanisms."

Operating Revenues

Retail Revenues**:** The table below presents Idaho Power’s retail revenues (in thousands), MWh sales (in thousands), and number of customers for the last three years.

	Year Ended December 31,		
	2018	2017	2016
Retail revenues:			
Residential (includes $34,625, $17,320, and $29,170, respectively, related to the FCA[1])	$ 530,527	$ 552,333	$ 514,954
Commercial (includes $1,299, $876, and $1,087, respectively, related to the FCA[1])	310,299	319,195	302,650
Industrial	190,130	195,124	182,590
Irrigation	158,001	150,030	156,505
Provision for sharing	(5,025)	—	—
Deferred revenue related to HCC relicensing AFUDC[2]	(8,780)	(10,706)	(10,706)
Total retail revenues	$ 1,175,152	$ 1,205,976	$ 1,145,993
Volume of Sales (MWh)			
Residential	5,135	5,355	5,004
Commercial	4,105	4,099	3,999
Industrial	3,371	3,346	3,243
Irrigation	1,976	1,771	1,950
Total retail MWh sales	14,587	14,571	14,196
Number of retail customers at year-end			
Residential	464,670	453,605	444,431
Commercial	71,680	70,411	69,344
Industrial	120	119	121
Irrigation	21,175	20,932	20,638
Total customers	557,645	545,067	534,534

(1) The FCA mechanism is an alternative revenue program and does not represent revenue from contracts with customers.
(2) As part of its January 30, 2009, general rate case order, the IPUC is allowing Idaho Power to recover a portion of the allowance for funds used during construction (AFUDC) on construction work in progress related to the HCC relicensing process, even though the relicensing process is not yet complete and the costs have not been moved to electric plant in service. Idaho Power is collecting approximately $8.8 million annually in the Idaho jurisdiction but is deferring revenue recognition of the amounts collected until the license is issued and the accumulated license costs approved for recovery are placed in service. Prior to the May 2018 Idaho Tax Reform Settlement Stipulation described in "Regulatory Matters" in this MD&A, Idaho Power was collecting $10.7 million annually.

Changes in rates, changes in customer demand, and changes in FCA mechanism revenues are the primary reasons for fluctuations in retail revenues 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 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 mild 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. Rates are also seasonally adjusted, providing for higher rates during summer peak load periods, and residential customer rates are tiered, providing for higher rates based on higher levels of usage. The seasonal and tiered rate structures contribute to seasonal fluctuations in revenues and earnings.

Retail Revenues - 2018 Compared with 2017: Retail revenues decreased $30.8 million in 2018 compared with 2017. The primary factors affecting retail revenues during the period were the following:

- Rates: Rate changes decreased retail revenues by $39.0 million in 2018 compared with 2017. As a direct result of settlement stipulations approved by the IPUC and OPUC during the second quarter of 2018 relating to income tax reform described further in "Regulatory Matters" in this MD&A, Idaho Power's revenues decreased approximately $22 million in 2018 compared with 2017. The timing of the revenue reductions may not align with decreases in income tax expense in any given period due to the method and timing of customer rate reductions provided for in the settlement stipulations, the nature and timing of income tax accruals, discrete items, and other items discussed in this MD&A. The rates include collection of amounts related to the PCA mechanism, which decreased revenues by $15.4 million in 2018 compared with 2017. The collection of amounts related to the PCA mechanism in rates has no effect on operating income as a corresponding amount is recorded as expense in the same period it is collected through rates.

- Customers: Customer growth of 2.3 percent increased retail revenues by $13.5 million in 2018 compared with 2017.

- Usage: Lower usage (on a per customer basis), primarily by residential customers, decreased retail revenues by $18.0 million during 2018 compared with 2017. Decreased usage was primarily the result of more mild temperatures in Idaho Power's service area during 2018 compared with 2017, which led to decreased usage by residential customers for heating and cooling. For 2018, a 6 percent decrease in usage per residential customer compared with 2017 was partially offset by a 9 percent increase in usage per irrigation customer. Precipitation in Idaho Power's service area during 2018 was significantly less than 2017, which led to increased usage by irrigation customers.

- Idaho FCA Revenue: The FCA mechanism, applicable to Idaho residential and small commercial customers, adjusts revenue each year to accrue, or defer, the difference between the authorized fixed-cost recovery amount per customer and the actual fixed costs per customer recovered by Idaho Power through volume-based rates during the year. Lower usage (on a per customer basis) by residential and small general service customers during 2018 increased the amount of FCA revenue accrued by $17.7 million compared with 2017.

- Sharing: During 2018, Idaho Power recorded $5.0 million as a provision against current revenues to be refunded to customers through a future rate reduction. If approved, the rate reduction would be included in PCA rates beginning in June 2019. Idaho Power did not record any provision for sharing in 2017. This revenue sharing arrangement, which requires Idaho Power to share with Idaho customers a portion of Idaho-jurisdiction earnings exceeding a 10.0 percent Idaho ROE, is related to the October 2014 Idaho Earnings Support and Sharing Settlement Stipulation. The October 2014 Idaho Earnings Support and Sharing Settlement Stipulation is described further in "Regulatory Matters" in this MD&A and in Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report.

Retail Revenues - 2017 Compared with 2016: Retail revenues increased $60.0 million in 2017 compared with 2016. The factors affecting retail revenues during the period are discussed below:

- Rates: Rate changes, including the revenue accruals provided for in the Valmy settlement stipulation, increased retail revenues by $39.8 million for 2017 compared with 2016. In the second quarter of 2017, the IPUC and OPUC each approved settlement stipulations related to Idaho Power’s plan to end its participation in coal-fired operations at the Valmy Plant by the end of 2025, which increased retail revenues collections and retail revenues accruals for 2017 compared with 2016. Colder winter temperatures in early 2017 and warmer summer temperatures during the third quarter of 2017 resulted in residential sales making up a larger portion of the sales mix and led to a greater proportion of residential sales in higher rate categories in Idaho Power's tiered rate structure in 2017 compared with 2016.

- Customers: Customer growth of 2.0 percent increased retail revenues by $12.1 million in 2017 compared with 2016.

- Usage: Higher usage (on a per customer basis), primarily by residential, industrial, and commercial customers increased retail revenues by $20.1 million in 2017 compared with 2016. Increased usage was primarily the result of warmer summer temperatures and colder winter temperatures in Idaho Power's service area, which increased usage by residential customers for cooling and heating. Cooling degree days and heating degree days were significantly higher in 2017 compared with 2016. These increases in usage were partially offset by an 11 percent decrease in usage per irrigation customer due to increased precipitation in Idaho Power's service area during 2017 compared with 2016, particularly in the first six months of 2017. Greater customer participation in energy efficiency programs, resulting in decreased usage, partially offset the increase in total usage during 2017 compared with 2016.

- Idaho FCA Revenue: The FCA mechanism, applicable to Idaho residential and small commercial customers, adjusts revenue each year to accrue, or defer, the difference between the authorized fixed-cost recovery amount per customer and the actual fixed costs per customer recovered by Idaho Power through volume-based rates during the year. Higher usage (on a per customer basis) by residential and small general service customers during 2017 decreased the amount of FCA revenue accrued by $12.1 million compared with 2016. Idaho Power accrued $18.2 million of FCA revenue in 2017 compared with $30.3 million of FCA revenue in 2016.

Wholesale Energy Sales**:** Wholesale energy sales consist primarily of long-term sales contracts, opportunity sales of surplus system energy, and sales into the Western EIM, and do not include derivative transactions. The table below presents Idaho Power’s wholesale energy sales for the last three years (in thousands, except for MWh amounts).

	Year Ended December 31,		
	2018	**2017**	**2016**
Wholesale energy revenues	$ 52,845	$ 24,790	$ 11,900
Wholesale MWh sold	2,246	1,934	742
Wholesale energy revenues per MWh	$ 23.53	$ 12.82	$ 16.04

Wholesale Energy Sales - 2018 Compared with 2017: In 2018, wholesale energy revenue increased by $28.1 million, or 113 percent, compared with 2017. Wholesale energy sales volumes increased 16 percent in 2018 compared with 2017, and the average price of wholesale energy sales was 84 percent higher for 2018 compared with 2017. During the fourth quarter of 2018, a natural gas pipeline ruptured in British Columbia, Canada, disrupting natural gas flows to the Pacific Northwest and Western Canada, driving up energy and natural gas prices in the region, including in Idaho Power's service area. An increase in purchased power, both in market purchases and in purchases under PURPA contracts, resulted in additional energy available for wholesale energy sales in 2018 compared with 2017. However, the high purchase price of power under federally mandated PURPA purchases is often in excess of the price at which Idaho Power sells the power in the wholesale energy markets. The increase in wholesale energy sales volumes and sales prices during 2018 compared with 2017 was also due to transactions in the Western EIM, which commenced in April 2018. Under the Western EIM, participating parties enable their systems to interact for automated intra-hour economic dispatch of generation from committed resources to serve loads.

Wholesale Energy Sales - 2017 Compared with 2016: For 2017, wholesale energy sales revenue increased by $12.9 million, or 108 percent compared with 2016 as generation from Idaho Power's hydroelectric plants increased due to significantly greater precipitation in 2017 compared with 2016. The increase in hydroelectric generation resulted in more energy available for wholesale energy sales in 2017 compared with 2016. The average price of wholesale energy sales was 20 percent lower for 2017 compared with 2016, as an increase in output from hydroelectric resources in the northwest United States region due to increased precipitation during the period, as well as additional output from new wind and solar projects throughout the region, increased surplus power available for sale and decreased wholesale power market prices.

Transmission Wheeling Revenues: Revenue from transmission wheeling increased $15.1 million, or 34 percent, in 2018 compared with 2017, largely due to Idaho Power's OATT rate that increased in October 2017 and, to a lesser extent, an increase in wheeling volumes. In October 2017, Idaho Power's OATT rate increased from $25.52 per kW-year to $34.90 per kW-year. In October 2018, the rate decreased to $31.25 per kW-year. Refer to "Regulatory Matters" in this MD&A for more information on Idaho Power's OATT rate. Revenue from transmission wheeling increased $11.5 million, or 35 percent, in 2017 compared with 2016, largely due to an increase in wheeling volumes, an increase in Idaho Power's OATT rate, and a new long-term wheeling agreement that became effective in July 2016.

Energy Efficiency Program Revenues: In both Idaho and Oregon, energy efficiency riders fund energy efficiency program expenditures. Expenditures funded through the riders are reported as an operating expense with an equal amount recorded in revenues, resulting in no net impact on earnings. The cumulative variances between expenditures and amounts collected through the riders are recorded as regulatory assets or liabilities. A liability balance indicates that Idaho Power has collected more than it has spent and an asset balance indicates that Idaho Power has spent more than it has collected. At December 31, 2018, Idaho Power's energy efficiency rider balances were a $5.3 million regulatory liability in the Idaho jurisdiction and a $1.4 million regulatory asset in the Oregon jurisdiction.

Operating Expenses

***Purchased Power*:** The table below presents Idaho Power's purchased power expenses and volumes for the last three years (in thousands, except for MWh amounts).

	Year Ended December 31,		
	2018	**2017**	**2016**
Expense			
PURPA contracts	$ 189,722	$ 169,788	$ 153,665
Other purchased power (including wheeling)	104,092	79,162	92,099
Total purchased power expense	$ 293,814	$ 248,950	$ 245,764
MWh purchased			
PURPA contracts	3,045	2,800	2,314
Other purchased power	2,386	1,442	2,023
Total MWh purchased	5,431	4,242	4,337
Cost per MWh from PURPA contracts	$ 62.31	$ 60.64	$ 66.41
Cost per MWh from other sources	$ 43.63	$ 54.90	$ 45.53
Weighted average - all sources	$ 54.10	$ 58.69	$ 56.67

Idaho Power is required by federal 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. The intermittent, non-dispatchable nature of most PURPA generation 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 its excess power in the wholesale power market at a significant loss. The other purchased power cost per MWh often exceeds the wholesale energy 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 wholesale energy 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 transactions that Idaho Power makes at current market prices may be noticeably different than the advance 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 power cost adjustment mechanisms.

Purchased Power - 2018 Compared with 2017: Purchased power expense increased $44.9 million, or 18 percent, in 2018 compared with 2017, primarily due to a 65 percent increase in the volume of other non-PURPA power purchases and a 9 percent increase in the volume of power purchases from generation projects under PURPA contracts. Other purchased power volumes increased during 2018 compared with 2017 due to wholesale gas and electricity market conditions and due to transactions in the Western EIM, which commenced in April 2018. These volume increases were partially offset by decreases in cost per MWh of power purchased from sources other than PURPA contracts.

Purchased Power - 2017 Compared with 2016: Purchased power expense increased $3.2 million, or 1 percent, in 2017 compared with 2016, primarily due to an increase in generation provided by PURPA solar contracts. The increase in PURPA volumes was partially offset by decreases in costs per MWh. Other purchased power expense decreased $12.9 million, or 14 percent, as abundant hydroelectric generation in 2017 compared with 2016 reduced the need for market purchases to meet load requirements.

***Fuel Expense*:** The table below presents Idaho Power’s fuel expenses and thermal generation for the last three years (in thousands, except per MWh amounts).

	Year Ended December 31,		
	2018	2017	2016
Expense			
Coal	$ 115,524	$ 107,894	$ 137,689
Natural gas[(1)]	17,674	37,935	41,802
Total fuel expense	$ 133,198	$ 145,829	$ 179,491
MWh generated			
Coal	3,274	3,284	4,045
Natural gas[(1)]	1,408	1,504	1,722
Total MWh generated	4,682	4,788	5,767
Cost per MWh - Coal	$ 35.29	$ 32.85	$ 34.04
Cost per MWh - Natural gas	$ 12.55	$ 25.22	$ 24.28
Weighted average, all sources	$ 28.45	$ 30.46	$ 31.12

(1) Includes a negligible amount of expense and generation related to the Salmon diesel-fired generation plant.

The majority of the fuel for Idaho Power’s jointly-owned coal-fired plants is purchased through long-term contracts, including purchases from BCC, a one-third owned joint venture of IERCo. The price of coal from BCC is subject to fluctuations in mine operating expenses, geologic conditions, and production levels. BCC supplies up to two-thirds of the coal used by the Jim Bridger plant. Natural gas is mainly purchased on the regional wholesale spot market at published index prices. In addition to commodity (variable) costs, both natural gas and coal expenses 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 - 2018 Compared with 2017: Fuel expense decreased $12.6 million, or 9 percent, in 2018 compared with 2017. In October 2018, a natural gas pipeline ruptured in British Columbia, Canada, which disrupted natural gas distribution to the Pacific Northwest region and Western Canada, and drove up energy prices in the region. In accordance with its ongoing risk management policies, Idaho Power held a number of financial gas hedges at the time of the rupture. Fuel expense in the fourth quarter of 2018 included $23.3 million in gains on financial gas hedges, which reduced natural gas fuel expense. Idaho Power was able to meet natural gas needs by purchasing physical gas from sources unaffected by the rupture. Most of these realized hedging gains will be a benefit to customers through the power cost adjustment mechanisms described below.

Fuel Expense - 2017 Compared with 2016: Fuel expense decreased $33.7 million, or 19 percent, in 2017 compared with 2016, due primarily to increased output from Idaho Power's hydroelectric plants, which reduced utilization of gas and coal generation. Generation from the hydroelectric plants increased 39 percent during 2017 compared with 2016.

***Power Cost Adjustment Mechanisms*:** Idaho Power's power supply costs (primarily purchased power and fuel expense, less wholesale energy sales) can vary significantly from year to year. Volatility of power supply costs arises from factors such as weather conditions, wholesale market prices, 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 power cost adjustment mechanisms in the Idaho and Oregon jurisdictions allow Idaho Power to recover from customers, 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 Idaho Power (5 percent), with the exception of PURPA power purchases and demand response program incentives, which are allocated 100 percent to customers. The Idaho deferral period, or PCA year, runs from April 1 through March 31. Amounts deferred during the PCA year are primarily recovered or refunded during the subsequent June 1 through May 31 period. Because of the power cost adjustment 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 below presents the components of the Idaho and Oregon power cost adjustment mechanisms for the last three years (in thousands).

	Year Ended December 31,		
	2018	2017	2016
Power supply cost accrual (deferral)	$ 41,535	$ 14,658	$ (43,841)
Amortization of prior year authorized balances	571	37,366	38,511
Total power cost adjustment expense	$ 42,106	$ 52,024	$ (5,330)

The power supply accruals represent the portion of the power supply cost fluctuations accrued under the power cost adjustment mechanisms. When actual power supply costs are lower than the amount forecasted in power cost adjustment rates, which was the case for 2018 and 2017, most of the difference is accrued. When actual power supply costs are higher than the amount forecasted in power cost adjustment rates, which was the case for 2016, 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 power cost adjustment year that were deferred or accrued in the prior power cost adjustment year (the true-up component of the power cost adjustment mechanism).

Power Cost Adjustment Mechanisms - 2018 Compared with 2017: Actual net power supply costs decreased in 2018 relative to forecasted costs, resulting in a change of $26.9 million—from accruals of $14.7 million to accruals of $41.5 million. The increase in accruals is due in part to lower natural gas fuel costs and purchased power, as explained above, combined with more surplus sales than forecasted. In addition, Idaho Power recorded $0.6 million of amortization of the prior-year authorized balances in 2018, compared with $37.4 million of amortization in 2017.

Power Cost Adjustment Mechanisms - 2017 Compared with 2016: Actual net power supply costs decreased in 2017 relative to forecasted costs, resulting in a change of $58.5 million—from deferrals of $43.8 million to accruals of $14.7 million. The change from deferrals in 2016 to accruals in 2017 is due in part to the lower fuel costs and purchased power, combined with more surplus sales than forecasted. The $37.4 million of amortization of prior year authorized balances in 2017 offsets the collection from customers of prior years' deferrals.

Other Operations and Maintenance Expenses**:** The changes in other O&M expenses for the periods presented are discussed below.

O&M - 2018 Compared with 2017: Other O&M expenses increased $17.8 million, or 5 percent, in 2018 compared with 2017. As provided by the settlement stipulation approved by the IPUC related to recent income tax reform, other O&M expenses in 2018 also included $4.0 million of non-cash amortization expense of regulatory deferrals that would otherwise be a future liability of Idaho customers. In 2018, compared with 2017, higher maintenance service costs led to a $4.2 million increase in transmission and distribution asset maintenance expenses, and higher variable employee-related costs led to an $8.4 million increase in labor and benefit expenses.

O&M - 2017 Compared with 2016: Other O&M expense decreased by $2.2 million in 2017 compared with 2016, primarily due to a $2.4 million decrease related to previously expensed energy efficiency rider-funded costs deemed to be prudently incurred and a $2.7 million decrease in thermal O&M expenses due to lower generation at thermal plants. These decreases in O&M were partially offset by a $2.5 million increase in O&M related to a settlement stipulation in Idaho that established the reasonableness of the HCC relicensing costs incurred through December 2015 as further discussed in "Regulatory Matters" in this MD&A.

Income Taxes

IDACORP's and Idaho Power's 2018 income tax expense decreased $31.3 million and $33.0 million, respectively, when compared with 2017. The decrease was primarily due to: (1) the Tax Cut and Jobs Act's reduction of the federal corporate tax rate from 35 percent to 21 percent that became effective January 1, 2018, (2) the remeasurement of deferred income tax balances related to IDACORP's 2017 consolidated income tax return filings, and (3) a flow-through income tax benefit at Idaho Power related to the tax deduction for a bond make-whole premium that was paid in 2018.

IDACORP's and Idaho Power's 2017 income tax expense increased $12.2 million and $14.1 million, respectively, when compared with 2016. The increase was primarily due to higher pre-tax earnings at Idaho Power in 2017, and the $5.6 million flow-through benefit of a tax deductible make-whole premium that Idaho Power paid in connection with the early redemption of long-term debt in 2016. There were no early redemptions of long-term debt in 2017. These increases in income tax expense were partially offset by greater net flow-through income tax items at Idaho Power.

For additional information relating to IDACORP's and Idaho Power's income taxes, the effects of the Tax Cuts and Jobs Act, and 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 continues to pursue 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 cash expenditures for property, plant, and equipment, excluding AFUDC, were $268 million in 2018, $277 million in 2017, and $287 million in 2016. Idaho Power expects these substantial capital expenditures to continue, with estimated total capital expenditures of approximately $1.5 billion expected over the period from 2019 through 2023.

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. As of February 15, 2019, 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 SEC on May 20, 2016, which may be used for the issuance of debt securities and common stock;
- Idaho Power's shelf registration statement filed with the SEC on May 20, 2016, which may be used for the issuance of first mortgage bonds and debt securities; $280 million is available for issuance 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 2019, the companies believe they will be able to meet capital requirements and fund corporate expenses during 2019 with a combination of existing cash and operating cash flows generated by Idaho Power's utility business, together with proceeds from either draws on credit facilities or Idaho Power's issuance of debt securities. 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 common stock, 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. To that end, in March 2018, Idaho Power issued $220 million in principal amount of 4.20% first mortgage bonds, Series K, maturing on March 1, 2048. In April 2018, Idaho Power redeemed, prior to its maturity, its $130 million in principal amount of 4.50% first mortgage bonds, Series H, due March 2020. In accordance with the redemption provisions of the original terms of the notes, the redemption included Idaho Power's payment of a make-whole premium of $4.6 million, the cost of which provided a flow-through tax deduction. Idaho Power used a portion of the net proceeds of the March 2018 sale of first mortgage bonds, medium term-notes to effect the redemption.

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, 2018, IDACORP's and Idaho Power's capital structures, as calculated for purposes of applicable debt covenants, were as follows:

	IDACORP	Idaho Power
Debt	44%	46%
Equity	56%	54%

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, income taxes, 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 2018 were $492 million and $418 million, respectively, an increase of $57 million for IDACORP and a $1 million increase for Idaho Power when compared with 2017. Significant items that affected the companies' operating cash flows in 2018 relative to 2017 were as follows:

- a $14 million increase and $16 million increase in IDACORP and Idaho Power net income, respectively;
- changes in regulatory assets and liabilities, mostly related to the relative amounts of power supply and fixed costs accrued or deferred and refunded or collected under Idaho rate mechanisms, decreased operating cash inflows by $9 million;
- changes in deferred taxes and in taxes accrued and receivable combined to decrease cash flows by $22 million and increase cash flows by $28 million at IDACORP and Idaho Power, respectively;
- Idaho Power received $29 million of distributions from IERCo's investment in BCC for 2018, compared with $23 million in 2017. Changes in distributions from year to year are primarily driven by changes in the timing of cash needs associated with BCC; and
- changes in working capital balances due primarily to timing, including fluctuations in accounts receivable, other current assets, accounts payable, and other current liabilities, as follows:
    - timing of collections of accounts receivable balances increased operating cash flows by $6 million for Idaho Power. IDACORP collected an $8 million receivable in 2017 from a legal settlement, offsetting the increase in 2018;
    - the changes in other current assets increased cash flows by $10 million, which was primarily due to a decrease in fuel stock as an increase in coal-fired generation in the fourth quarter of 2018 compared with 2017 decreased the related coal inventory; and
    - timing of accounts payable payments increased operating cash flows by $47 million for IDACORP and decreased operating cash flows by $64 million for Idaho Power (the difference relates to the timing of estimated income tax payments from Idaho Power to IDACORP).

IDACORP's and Idaho Power's operating cash inflows in 2017 were $435 million and $417 million, respectively, an increase of $91 million for IDACORP and $110 million for Idaho Power when compared with 2016. Significant items that affected the companies' operating cash flows in 2017 relative to 2016 were as follows:

- a $15 million increase and $17 million increase in IDACORP and Idaho Power net income, respectively, which includes a $19 million increase in non-cash depreciation and amortization at both companies;
- 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, increased operating cash inflows by $63 million. The increase is mostly related to the relative amounts of power supply and fixed costs deferred and collected under the Idaho power cost adjustment and FCA mechanisms, partially offset by revenues accrued in excess of collections from the Valmy Plant settlement stipulation that will be collected in future periods;
- changes in deferred taxes and in taxes accrued and receivable combined to increase cash flows by $1 million and decrease cash flows by $23 million at IDACORP and Idaho Power, respectively;
- changes in working capital balances due primarily to timing, including fluctuations in accounts receivable, other current assets, and accounts payable, as follows:
    - timing of collections of accounts receivable balances increased operating cash flows by $7 million for IDACORP and decreased operating cash flows by $6 million for Idaho Power. IDACORP collected an $8 million receivable in 2017 from a legal settlement;

- ◦ the changes in other current assets increased cash flows by $14 million, which was primarily due to fluctuations in the balance in accrued unbilled revenues as energy sales near the end of the respective periods were impacted by weather; and
- ◦ timing of accounts payable payments decreased operating cash flows by $31 million for IDACORP and increased operating cash flows by $25 million for Idaho Power (the difference relates to a $55 million payable from Idaho Power to IDACORP relating to estimated income tax payments).

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 $278 million, $285 million, and $297 million in 2018, 2017, and 2016, 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 $22 million and $6 million in 2018 and 2017 from Boardman-to-Hemingway project joint permitting participants relating to a portion of these construction expenditures.

Idaho Power has a Rabbi trust designated to provide funding for obligations of its nonqualified defined benefit plans. In the Rabbi trust, Idaho Power purchased available-for-sale securities of $11 million in both 2018 and 2017, and $15 million in 2016. Idaho Power received $5 million of proceeds from the sales of available-for-sale securities in both 2018 and 2017, and $16 million in 2016. Idaho Power did not use any of these proceeds to acquire company-owned life insurance in 2018 and 2017 but used $10 million of the proceeds to acquire company-owned life insurance in 2016.

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 2018, 2017, and 2016:

- on March 16, 2018, Idaho Power issued $220 million in principal amount of 4.20% first mortgage bonds Series K, maturing March 1, 2048;
- on April 17, 2018, Idaho Power redeemed, prior to maturity, $130 million of its 4.50% first mortgage bonds, Series H, due March 1, 2020, and paid a related make-whole premium of $4.6 million;
- on March 10, 2016, Idaho Power issued $120 million in principal amount of 4.05% first mortgage bonds, Series J, maturing on March 1, 2046;
- on April 11, 2016, Idaho Power redeemed, prior to maturity, $100 million in principal amount of 6.15% first mortgage bonds, Series H, due April 1, 2019, and paid a related make-whole premium of $14 million;
- IDACORP and Idaho Power paid dividends of approximately $121 million, $113 million, and $105 million in 2018, 2017, and 2016, respectively;
- IDACORP's net change in commercial paper borrowings used cash of $22 million and provided cash of $2 million in 2017 and 2016, respectively; and
- Idaho Power borrowed $22 million in commercial paper in December 2016, which was paid off in January of 2017.

Financing Programs and Available Liquidity

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 and May 2016, 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 is effective through May 31, 2019, subject to extension upon request to the IPUC. The OPUC's and WPSC's orders do not impose a time limitation for issuances, but the OPUC order does impose a number of other conditions, including a requirement that the interest rates for the debt securities or first mortgage bonds fall within either (a) designated spreads over comparable U.S. Treasury rates or (b) a maximum interest rate limit of seven percent.

On September 27, 2016, Idaho Power entered into a selling agency agreement with seven 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, secured medium term notes, Series K (Series K Notes), under Idaho Power's Indenture of Mortgage and Deed of Trust, dated as of October 1, 1937, as amended and supplemented (Indenture). At the same time, Idaho Power entered into the Forty-eighth Supplemental Indenture, dated as of September 1, 2016, to the Indenture (Forty-eighth Supplemental Indenture). The Forty-eighth Supplemental Indenture provides for, among other items, (a) the issuance of up to $500 million in aggregate principal amount of Series K Notes pursuant to the Indenture and (b) the increase of the maximum amount of obligations to be secured by the Indenture to $2.5 billion (which maximum amount may be further increased or decreased by Idaho Power without the consent of the holders of first mortgage bonds). As of the date of this report, Idaho Power has $280 million available for the issuance of first mortgage bonds, including Series K Notes, or debt securities under the selling agency agreement.

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 $2.5 billion, and as a result, the maximum amount of first mortgage bonds Idaho Power could issue as of December 31, 2018, was limited to approximately $669 million. Idaho Power may increase the $2.5 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, 2018, Idaho Power could issue approximately $1.9 billion of additional first mortgage bonds based on retired first mortgage bonds and total unfunded property additions.

Refer to Note 5 - "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.

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, 2018, the leverage ratios for IDACORP and Idaho Power were 44 percent and 46 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, 2018, IDACORP and Idaho Power believe they were in compliance with all facility covenants. Further, as of the date of this report, IDACORP and Idaho Power do not believe they will be in violation or breach of their respective debt covenants during 2019.

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.

While the credit facilities provide for an original maturity date of November 6, 2020, the credit agreements grant IDACORP and Idaho Power the right to request up to two one-year extensions, in each case subject to certain conditions. On November 7, 2016, IDACORP and Idaho Power executed the first extension agreement and on November 7, 2017, executed the second extension agreement with the consent of all the lenders, extending the maturity date under both credit agreements to November 4, 2022. No other terms of the credit facilities, including the amount of permitted borrowing under the credit agreements, were affected by the extensions.

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 (in thousands):

	December 31, 2018		December 31, 2017	
	IDACORP(2)	Idaho Power	IDACORP(2)	Idaho Power
Revolving credit facility	$ 100,000	$ 300,000	$ 100,000	$ 300,000
Commercial paper outstanding	—	—	—	-
Identified for other use(1)	—	(24,245)	—	(24,245)
Net balance available	$ 100,000	$ 275,755	$ 100,000	$ 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.

The table below presents additional information about short-term commercial paper borrowing during the years ended December 31, 2018 and 2017:

	December 31, 2018		December 31, 2017	
	IDACORP(1)	Idaho Power	IDACORP(1)	Idaho Power
Commercial paper:				
Year end:				
Amount outstanding	$ —	$ —	$ —	$ —
Weighted average interest rate	—%	—%	—%	—%
Daily average amount outstanding during the year	$ —	$ —	$ 588	$ 839
Weighted average interest rate during the year	—%	—%	1.42%	1.12%
Maximum month-end balance	$ —	$ —	$ 2,425	$ —

(1) Holding company only.

At February 15, 2019, IDACORP had no loans outstanding under its credit facility and no commercial paper outstanding, and Idaho Power had no loans outstanding under its credit facility and no commercial paper outstanding.

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 Moody’s Investors Service and Standard & Poor’s Ratings Services 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
Standard & Poor's Rating Services:		
Corporate Credit Rating	BBB	BBB
Rating Outlook	Stable	Stable
Short-Term Rating	A-2	A-2
Senior Secured Debt	None	A-

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, 2018, Idaho Power had no performance assurance collateral posted. 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, 2018, the amount of additional collateral that could be requested upon a downgrade to below investment grade is approximately $10.5 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 cash construction expenditures, excluding AFUDC, were $268 million during the year ended December 31, 2018. The cash expenditure amount excludes net costs of removing assets from service. The table below presents Idaho Power's estimated accrual-basis expenditures for construction for 2019 through 2023 (in millions of dollars). The amounts in the table exclude AFUDC but include net costs of removing assets from service that Idaho Power expects would be eligible to be included in rate base in future rate case proceedings. 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.

	2019	2020	2021-2023
Expected capital expenditures (excluding AFUDC)	$ 280-290	$ 285-300	$ 875-925

Infrastructure Projects: A significant portion of expected capital expenditures included in the five-year forecast above relate to a large number of small projects as Idaho Power continues to add to its system to accommodate growth and improve reliability and operational effectiveness. These projects involve significant capital expenditures. Examples of anticipated system enhancements planned for 2019 through 2023 and estimated costs include the following:

- $35-$65 million per year for construction and replacement of transmission lines and stations other than the Boardman-to-Hemingway and Gateway West projects;
- $85-$105 million per year for construction and replacement of distribution lines and stations, including replacement of underground distribution cables;
- $20-$40 million per year for ongoing improvements and replacements at coal- and natural gas-fired plants;
- $50-$70 million per year for hydroelectric plant improvement programs, including relicensing costs; and
- $40-$60 million per year for general plant improvements, such as land and buildings, vehicles, information technology, and communication equipment.

Other Major Infrastructure Projects: Idaho Power has recently completed or 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.

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. In January 2012, Idaho Power entered into a joint funding agreement with PacifiCorp and the Bonneville Power Administration 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. Total cost estimates for the project are between $1.0 billion and $1.2 billion, including Idaho Power's AFUDC. This cost estimate is preliminary and 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 addition to approximately $50 million of Idaho Power's share of costs related to early construction efforts, which are primarily included in the period 2021-2023. These preliminary estimates of Idaho Power’s share of early construction costs could significantly change as the construction timeline nears and as the project participants further align on future activities and estimates.

Approximately $100 million, including AFUDC, has been expended on the Boardman-to-Hemingway project through December 31, 2018. Pursuant to the terms of the joint funding arrangements, Idaho Power has received $70 million as of December 31, 2018, due from project participants for their share of costs. As of the date of this report, no material participant reimbursements are outstanding. Joint permitting participants are obligated to reimburse Idaho Power for their share of any future project permitting expenditures incurred by Idaho Power.

The permitting phase of the Boardman-to-Hemingway project is subject to federal review and approval by the BLM, the U.S. Forest Service, the Department of the Navy, and certain other federal agencies. The BLM issued its record of decision for the project in November 2017, approving a right-of-way grant for the project to cross approximately 86 miles of BLM-administered land. The U.S. Forest Service issued its record of decision in November 2018 authorizing the project to cross approximately seven miles of National Forest lands. Idaho Power expects the U.S. Forest Service to issue its right-of-way easement in 2019. Idaho Power expects the Department of the Navy to issue its decision on whether to approve the project to cross approximately seven miles of Department of the Navy lands in the first quarter of 2019.

In the separate Oregon state permitting process, in September 2018, Idaho Power's application for site certificate was deemed complete by the Oregon Department of Energy (ODOE). The ODOE is expected to issue a draft proposed order on the application in the first half of 2019 providing the ODOE's recommendation on whether to issue a site certificate for construction in Oregon. Given the status of ongoing permitting activities and the construction period, Idaho Power expects the in-service date for the transmission line to be in 2026 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 located near Boise, Idaho. In January 2012, Idaho Power and PacifiCorp entered a joint funding agreement for permitting of the project. Idaho Power has expended approximately $38 million, including AFUDC, for its share of the permitting phase of the project through December 31, 2018. 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 $250 million and $450 million, including AFUDC. Idaho Power's estimated share of the permitting phase of the project (excluding AFUDC) is included in the capital requirements table above. Idaho Power's share of potential early construction costs are excluded from the capital requirements table above because the timing of construction of Idaho Power's portion of the project is uncertain.

The permitting phase of the Gateway West project was subject to review and approval of the BLM. The BLM released its record of decision in November 2013 for eight of the ten transmission line segments. In May 2017, a federal bill was signed into law that issued a right-of-way for certain portions of the remaining Gateway West segments. In April 2018, the BLM published its record of decision for the outstanding portions of the remaining segments. Idaho Power and PacifiCorp continue to coordinate the timing of next steps to best meet customer and system needs.

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. The past and anticipated future costs associated with obtaining a new long-term license for the HCC are significant. 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 $30 million to $40 million until issuance of the license, which Idaho Power estimates will occur no earlier than 2022. 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. In December 2016, Idaho Power filed an application with the IPUC requesting a determination that Idaho Power's expenditures of $220.8 million through year-end 2015 on relicensing of the HCC were prudently incurred, and thus eligible for future inclusion in retail rates in a future rate proceeding. In December 2017, Idaho Power filed with the IPUC a settlement stipulation signed by Idaho Power, the IPUC staff, and a third party intervenor recognizing that a total of $216.5 million in expenditures were reasonably incurred, and therefore should be eligible for inclusion in customer rates at a later date. As a result of filing the settlement stipulation, Idaho Power recorded a $5.0 million pre-tax charge in 2017, which included $4.3 million for costs incurred through 2015 as well as $0.7 million related to associated costs incurred in 2016 and 2017. Of the $5.0 million pre-tax charge in 2017, $2.5 million was recorded as Other O&M expense and $2.5 million was recorded as a reduction to AFUDC. In April 2018, the IPUC issued an order approving the settlement stipulation as filed with IPUC and determined the associated costs to be reasonably and prudently incurred.

Jim Bridger Plant Selective Catalytic Reduction Equipment: Idaho Power and the plant co-owners completed installation of selective catalytic reduction (SCR) equipment to reduce nitrogen dioxide (NO_2) emissions at the Jim Bridger power plant, in order to comply with regional haze rules. The regional haze rules provided for installation of SCR on unit 3 and unit 4. The rules provide for an equivalent technology for NO_2 reductions on unit 2 by 2021 and unit 1 by 2022.The unit 3 SCR was operating as of November 2015, and the unit 4 SCR was operating as of November 2016. In light of the substantial estimated cost of SCR installation, as of the date of this report, Idaho Power continues to assess whether to move forward with the installation of SCR on units 1 and 2 at the Jim Bridger power plant. The expected capital expenditures in the table above do not include any estimated expenditures relating to the installation of SCR on units 1 and 2.

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 - Environmental Regulation and Costs" 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 IRP. The IRP seeks to forecast Idaho Power's loads and resources for a 20-year period, analyzes potential supply-side, demand-side, and transmission options, and identifies potential near-term and long-term actions. Idaho Power filed its most recent IRP with the IPUC and OPUC in June 2017. The 2017 IRP identified a preferred resource portfolio and action plan, which includes the completion of the Boardman-to-Hemingway transmission line by 2026, the end to Idaho Power's participation in coal-fired operations at the Valmy Plant units 1 and 2 in 2019 and 2025, respectively, and the early retirement of Jim Bridger units 1 and 2 in 2032 and 2028, respectively, with no other new resource needs prior to 2026. However, as noted in the 2017 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, fuel commodity prices, environmental requirements, the actual completion date of the Boardman-to-Hemingway transmission project, and the economics and logistics of plant operation and retirements. These uncertainties, as well as others, could result in changes to the desirability of the preferred portfolio and adjustments to the timing and nature of anticipated and actual actions. Additional information on Idaho Power's 2017 IRP is included in Part I, Item 1 - "Business - Resource Planning" in this report.

Defined Benefit Pension Plan Contributions and Recovery

Idaho Power contributed $40 million to its defined benefit pension plan in each year in 2018, 2017, and 2016. Idaho Power estimates that it has no minimum contribution requirement for 2019. Depending on market conditions and cash flow considerations in 2019, Idaho Power could contribute up to $40 million to the pension plan during 2019. 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. Beyond 2019, Idaho Power expects continuing significant contribution obligations under the pension plan. Refer to Note 12 - "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. At December 31, 2018 and 2017, Idaho Power's deferral balance associated with the Idaho jurisdiction was $148 million and $128 million, respectively. 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 million of deferred pension costs annually, and has applied $68 million against the deferred amount under its Idaho sharing mechanisms since 2011. The primary impact of pension contributions is on the timing of cash flows, as cost recovery lags behind the timing of contributions.

Income Tax Reform

In December 2017, the Tax Cuts and Jobs Act was signed into law, which among other things, lowered the corporate federal income tax rate from 35 percent to 21 percent and modified or eliminated certain federal income tax deductions for corporations. In March 2018, Idaho House Bill 463 was signed into law reducing the Idaho state corporate income tax rate from 7.4 percent to 6.925 percent. The majority of the law changes, including the rate reductions, became effective on January 1, 2018. See "Regulatory Matters" in this MD&A for more information on the related regulatory proceedings and financial impacts.

Contractual Obligations

The following table presents IDACORP's and Idaho Power's contractual cash obligations as of December 31, 2018, for the respective periods in which they are due:

	Payments Due by Period				
	Total	2019	2020-2021	2022-2023	Thereafter
	(millions of dollars)				
Long-term debt[1]	$ 1,855	$ —	$ 100	$ 150	$ 1,605
Future interest payments[2]	1,565	85	166	159	1,155
Purchase obligations:					
Maintenance and service agreements[3]	131	34	26	16	55
FERC and other industry-related fees[3]	128	14	25	25	64
Cogeneration and small power production	4,042	239	490	508	2,805
Fuel supply agreements	201	43	57	17	84
Other[3][4]	51	3	8	8	32
Pension and postretirement benefit plans[5]	326	11	110	153	52
Other long-term liabilities - IDACORP only[3]	2	—	—	—	2
Total	$ 8,301	$ 429	$ 982	$ 1,036	$ 5,854

(1) For additional information, see Note 5 – "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, 2018.

(3) Approximately $20 million of the amounts in maintenance and service agreements, $71 million of the amounts in FERC and other industry-related fees, $29 million of the amounts in other purchase obligations, and $2 million of the amounts in IDACORP only other long-term liabilities are contracts that do not specify terms related to expiration. As these contracts are presumed to continue indefinitely, ten years of information, estimated based on current contract terms, has been included in the table for presentation purposes.

(4) Other purchase obligations include right-of-way easements and the joint-operating agreement payments.

(5) Idaho Power estimates pension contributions based on actuarial data. As of the date of this report, Idaho Power cannot estimate pension contributions beyond 2023 with any level of precision, and amounts through 2023 are estimates only and are subject to change. For more information on pension and postretirement plans, refer to Note 12 – "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 2018, 2017, and 2016, IDACORP's board of directors voted to increase the quarterly dividend to $0.63 per share, $0.59 per share, and $0.55 per share of IDACORP common stock, respectively. IDACORP's dividends during 2018 were 53.5 percent of actual 2018 earnings.

For additional information relating to IDACORP and Idaho Power dividends, including restrictions on IDACORP's and Idaho Power's payment of dividends, see Note 7 – "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. 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 (WDEQ), was $58.4 million at December 31, 2018, representing IERCo's one-third share of BCC's total reclamation obligation of $175.2 million. BCC has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. At December 31, 2018, the value of the reclamation trust fund totaled $101.9 million. During 2018, the reclamation trust fund made $6.7 million in distributions 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, and does, add a per-ton surcharge to coal sales, all of which are made to the Jim Bridger plant. 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 regulatory strategy 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 and magnitude 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 customer growth, power cost adjustment mechanisms, tariff riders, and other mechanisms to reduce the impact of 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. Idaho Power continues to assess the need and timing of filing a general rate case in its two retail jurisdictions, based on its consideration of the factors described above, but does not anticipate filing a general rate case in 2019.

Notable Retail Rate Changes in Idaho and Oregon

Included in the table that follows are notable regulatory developments during 2018, 2017, and 2016 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 Rate Impact (millions)(1)
May 2018 Idaho Tax Reform Settlement Stipulation - Idaho base rates	6/1/2018	$ (19)
May 2018 Idaho Tax Reform Settlement Stipulation - Idaho PCA(2)	6/1/2018	(8)
2018 Idaho PCA	6/1/2018	(23)
2018 Idaho FCA	6/1/2018	(19)
Oregon Tax Reform Settlement Stipulation	6/1/2018	(1)
Oregon Valmy Plant Accelerated Depreciation Settlement Stipulation	6/1/2018	2
Oregon Valmy Plant Settlement Stipulation	7/1/2017	1
Idaho Valmy Plant Settlement Stipulation	6/1/2017	13
2017 Idaho PCA(3)	6/1/2017	11
2017 Idaho FCA	6/1/2017	7
2016 Idaho PCA(4)	6/1/2016	17
2016 Idaho FCA	6/1/2016	11

(1) The annual amount collected or refunded in rates is typically not recovered or refunded on a linear basis (i.e., 1/12th per month), and is instead recovered or refunded in proportion to retail sales volumes. The rate changes for the Idaho PCA and FCA are applicable only for one-year periods.

(2) 2018 Idaho PCA rates include $7.8 million decrease for the income tax benefits accrued from January 1 to May 31, 2018, and the income tax benefits related to Idaho Power's OATT rate. See "Income Tax Reform - Regulatory Treatment" below for more information.

(3) 2017 Idaho PCA rates reflect the application of $13.0 million of surplus Idaho energy efficiency rider funds.

(4) 2016 Idaho PCA rates reflect the application of (a) a customer rate credit of $3.2 million for sharing of revenues with customers for the year 2015 under the terms of an October 2014 settlement stipulation and (b) $4.0 million of surplus Idaho energy efficiency rider funds.

Idaho and Oregon General Rate Cases

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. In September 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 PCA mechanism and instead results in collecting that portion through base rates.

Valmy Base Rate Adjustment Settlement Stipulations

In May 2017, the IPUC approved a settlement stipulation, effective June 1, 2017, allowing accelerated depreciation and cost recovery for the Valmy Plant. The settlement stipulation provides for an increase in Idaho jurisdictional revenues of $13.3 million per year, and (1) levelized collections and associated cost recovery through December 2028, (2) accelerated depreciation on unit 1 through 2019 and unit 2 through 2025, (3) Idaho Power to use prudent and commercially reasonable efforts to end its participation in the operation of unit 1 by the end of 2019 and unit 2 by the end of 2025, and (4) a filing no later than December 31, 2019 that would include actual and planned incremental investments in unit 2, including updated financial analysis regarding the lowest costs options for unit 2. The costs intended to be recovered by the increased jurisdictional revenues include current investments as of May 31, 2017 in both units, forecasted unit 1 investments from 2017 through 2019, and forecasted decommissioning costs for unit 1 and unit 2, offset by forecasted operation and maintenance costs savings. The settlement stipulation also provides for the regulatory accrual or deferral of the difference between actual revenue requirements and levelized collections, and provides for the regulatory accrual or deferral of the difference between actual costs incurred (including accelerated depreciation expense on unit 1 through 2019 and unit 2 through 2025) compared with costs permitted to be recovered during the cost recovery period specified in the settlement stipulation (including depreciation expense through 2028). If actual costs incurred differ from forecasted amounts included in the settlement stipulation, collection or refund of any differences would be subject to regulatory approval.

In June 2017, the OPUC also approved a settlement stipulation allowing for accelerated depreciation of units 1 and 2 through December 31, 2025, cost recovery of incremental Valmy Plant investments through May 31, 2017, and forecasted decommissioning costs. The settlement stipulation provides for an increase in the Oregon jurisdictional revenue requirement of $1.1 million, effective July 1, 2017, with yearly adjustments, if warranted. As part of the May 2018 Oregon Income Tax Reform Settlement Stipulation described below, the OPUC also deemed prudent Idaho Power's decision to pursue the end of its participation in coal-fired operations of unit 1 by the end of 2019 and approved Idaho Power's request to recover annual incremental accelerated depreciation relating to unit 1, beginning June 1, 2018, and ending December 31, 2019, resulting in a $2.5 million annualized revenue requirement.

Other Notable Regulatory Matters

December 2011 Idaho Earnings Support and Sharing Settlement Stipulation: 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 accumulated deferred investment tax credits (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. Under the December 2011 Idaho Earnings Support and Sharing 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.

October 2014 Idaho Earnings Support and Sharing Settlement Stipulation: 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 Idaho Earnings Support and Sharing Settlement Stipulation provide the companies with a greater degree of earnings stability than would be possible without the terms of the stipulation in effect. The October 2014 Idaho Earning Support and Sharing Settlement Stipulation was modified and indefinitely extended, as described in "Income Tax Reform - Regulatory Treatment" below.

In 2018, Idaho Power recorded a $5.0 million provision against current revenue for sharing with customers, as its full-year Idaho ROE for 2018 was above 10.0 percent. In both 2017 and 2016, Idaho Power did not record any additional ADITC amortization or any provision for sharing with customers, as its Idaho ROE in both years was between 9.5 percent and 10.0 percent. Accordingly, at December 31, 2018, the full $45 million of additional ADITC remains available for future use under the terms of the October 2014 Idaho Earnings Support and Sharing Settlement Stipulation.

Idaho Power recorded the following for sharing with customers under the December 2011 and October 2014 Idaho Settlement Stipulations (in millions):

Year	Recorded as Refunds to Customers	Recorded as a Pre-tax Charge to Pension Expense	Total
2018	$ 5.0	$ —	$ 5.0
2017	—	—	—
2016	—	—	—
2015	3.2	—	3.2
2014	8.0	16.7	24.7
2013	7.6	16.5	24.1
2012	7.2	14.6	21.8
2011[(1)]	27.1	20.3	47.4
Total	$ 58.1	$ 68.1	$ 126.2

(1) The 2011 sharing amounts were recorded pursuant to a regulatory mechanism preceding the December 2011 Idaho Earnings Support and Sharing Settlement Stipulation.

Income Tax Reform - Regulatory Treatment: In December 2017, the Tax Cuts and Jobs Act was signed into law, which, among other things, lowered the corporate federal income tax rate from 35 percent to 21 percent and modified or eliminated certain federal income tax deductions for corporations. In March 2018, Idaho House Bill 463 was signed into law reducing the Idaho state corporate income tax rate from 7.4 percent to 6.925 percent. In January 2018, the IPUC issued an order requiring utilities within its jurisdiction, including Idaho Power, to (1) record a regulatory liability for the estimated Idaho-jurisdictional share of financial benefits after January 1, 2018, from the changes in federal income tax law under the Tax Cuts and Jobs Act, and (2) file a report with the IPUC by March 30, 2018, identifying and quantifying the financial impact of the income tax changes on the utility, along with proposed tariff schedule changes that would adjust the utility's rates and corresponding revenues to reflect the utility's modified federal tax obligations under the Tax Cuts and Jobs Act. The IPUC order required Idaho Power to estimate the income tax reform changes by comparing actual 2017 federal income tax components with what those federal income tax components would have been if the Tax Cuts and Jobs Act had been effective for the full-year 2017.

In March 2018, Idaho Power made a filing with the IPUC providing the results of its pro forma analysis indicating pro forma annual income tax reform expense reductions, composed of a current income tax expense reduction and a deferred income tax expense reduction. In May 2018, the IPUC issued an order approving a settlement stipulation (May 2018 Idaho Tax Reform Settlement Stipulation) related to income tax reform. Beginning June 1, 2018, the settlement stipulation provides an annual (a) $18.7 million reduction to Idaho customer base rates and (b) $7.4 million amortization of existing regulatory deferrals for specified items or future amortization of other existing or future unspecified regulatory deferrals that would otherwise be a future liability recoverable from Idaho customers. Additionally, a one-time benefit of a $7.8 million rate reduction is being provided to Idaho customers through PCA mechanism rates for the period from June 1, 2018 through May 31, 2019, for the income tax reform benefits accrued from January 1, 2018 to May 31, 2018, and the income tax reform benefits related to Idaho Power's OATT rate. The amount provided via the PCA mechanism will decrease to $2.7 million on June 1, 2019, for income tax reform benefits related to Idaho Power's OATT rate and will cease on June 1, 2020, to reflect the impact of a full year of reduced OATT third-party transmission revenues.

The May 2018 Idaho Tax Reform Settlement Stipulation provides for the extension of the October 2014 Idaho Earnings Support and Sharing Settlement Stipulation described above beyond the initial termination date of December 31, 2019, with modified terms related to the ADITC and revenue sharing mechanism to become effective beginning January 1, 2020. Neither the October 2014 Idaho Earnings Support and Sharing Settlement Stipulation nor the May 2018 Idaho Tax Reform Settlement Stipulation impose a moratorium on Idaho Power filing a general rate case or other form of rate proceeding in Idaho during their respective terms.

Also in May 2018, the OPUC issued an order approving a settlement stipulation that provides for an annual $1.5 million reduction to Oregon customer base rates beginning June 1, 2018, through May 31, 2020, related to income tax reform. Unless resolved in a regulatory proceeding before, the settlement stipulation requires Idaho Power to file a deferral request with the OPUC by December 31, 2019, to begin tracking income tax reform benefits beginning January 1, 2020, at which time Idaho Power, the OPUC staff, and other interested parties will discuss the methodology to quantify potential future income tax reform benefits.

For more information on the settlement stipulations and their impacts on results, see Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report.

Customer-Owned Generation Filing: In July 2017, Idaho Power filed an application with the IPUC related to residential and small general service customers who install their own on-site generation, seeking to create two new customer classes, with no request to change pricing or compensation. In May 2018, the IPUC issued an order authorizing the creation of the new customer classes. In October 2018, Idaho Power filed petitions requesting the IPUC open two new proceedings to study the fixed-costs of providing electric service to customers, and to study the costs, benefits, and compensation of net excess energy supplied by customer on-site generation, respectively. In November 2018, the IPUC opened the proceedings. As of the date of this report, Idaho Power and the parties in both proceedings are continuing to determine the procedural and substantive scope for each proceeding.

Western Energy Imbalance Market Costs: Idaho Power's participation in the Western EIM commenced on April 4, 2018. The Western EIM is intended to reduce the power supply costs to serve customers through more efficient dispatch within the hour of a larger and more diverse pool of resources, to integrate intermittent power from renewable generation sources more effectively, and to enhance reliability. Financial benefits or costs resulting from participation in the Western EIM are subject to Idaho Power's PCA mechanism as described in Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report. In January 2017, the IPUC issued an order authorizing deferral accounting treatment for costs associated with joining the Western EIM. In November 2017, Idaho Power filed an application with the IPUC requesting authorization to establish an interim method of recovery for Western EIM-related costs. In July 2018, the IPUC issued an order approving a settlement stipulation that provides for recovery through Idaho Power's PCA mechanism. For more information on the order and its impact on financial results, see Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report.

Deferred (Accrued) Net Power Supply Costs

Deferred (accrued) 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 (accrued) power supply costs are recorded on the balance sheets for future recovery (refund) through customer rates. Idaho Power's power cost adjustment mechanisms in its Idaho and Oregon jurisdictions provide for annual adjustments to the rates charged to retail customers. The power cost adjustment mechanisms 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 power cost adjustment rate changes in recent years include year-to-year volatility in hydroelectric generation conditions, market energy prices and the volume of wholesale energy sales, power purchase costs from renewable energy projects, income tax reform, and revenue sharing under Idaho regulatory settlement stipulations. From year to year, these factors can vary significantly, which can result in significant accruals and deferrals under the power cost adjustment mechanisms. The power cost adjustment 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 power cost adjustment rates.

The following table summarizes the change in deferred (accrued) net power supply costs over the prior two years (in millions):

	Idaho	Oregon	Total
Balance at December 31, 2016	$ 53.5	$ 0.4	$ 53.9
Current period net power supply costs accrued	(14.7)	—	(14.7)
Energy efficiency rider funds transferred to Idaho PCA mechanism	(13.0)	—	(13.0)
Prior amounts recovered through rates	(26.1)	(0.5)	(26.6)
Sulfur Dioxide (SO_2) allowance and renewable energy certificate (REC) sales	(2.1)	(0.1)	(2.2)
Interest and other	0.2	0.1	0.3
Balance at December 31, 2017	(2.2)	(0.1)	(2.3)
Current period net power supply costs accrued	(41.5)	—	(41.5)
Tax reform revenue accrual to be refunded through Idaho PCA, net of amounts refunded	(1.9)	—	(1.9)
Western EIM cost recovery to be collected through Idaho PCA	2.2	—	2.2
Prior amounts refunded through rates	4.2	—	4.2
SO_2 allowance and REC sales	(2.6)	(0.1)	(2.7)
Interest and other	(0.3)	—	(0.3)
Balance at December 31, 2018	$ (42.1)	$ (0.2)	$ (42.3)

Open Access Transmission Tariff Rate Proceedings

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. In August 2018, Idaho Power filed its 2018 final transmission rate with the FERC, reflecting a transmission rate of $31.25 per kW-year, to be effective for the period from October 1, 2018, to September 30, 2019. A "kW-year" is a unit of electrical capacity equivalent to 1 kilowatt of power used for 8,760 hours. Idaho Power's final rate was based on a net annual transmission revenue requirement of $123.1 million. The OATT rate in effect from October 1, 2017, to September 30, 2018, was $34.90 per kW-year based on a net annual transmission revenue requirement of $130.4 million. The decrease in the OATT rate is largely attributable to an increase in short-term transmission revenues in 2017, which serves as an offset to the transmission revenue requirement. Historic OATT rate information is included in Note 3 - "Regulatory Matters" to the consolidated financial statements included in this report.

Relicensing of Hydroelectric Projects

Overview: Idaho Power, like other utilities that operate non-federal 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. Idaho Power expects to seek recovery of relicensing costs and costs related to a new long-term license through the regulatory process and, in December 2016, submitted a request for a determination of prudence of HCC relicensing costs, which is described below. Relicensing costs of $297 million (including AFUDC) for the HCC, Idaho Power's largest hydroelectric complex and a major relicensing effort, were included in construction work in progress at December 31, 2018. As of the date of this report, the IPUC authorizes Idaho Power to include in its Idaho jurisdiction rates approximately $8.8 million annually of AFUDC relating to the HCC relicensing project. Prior to the May 2018 Tax Reform Settlement Stipulation described in Note 3 - "Regulatory Matters," Idaho Power was collecting $10.7 million annually. Collecting these amounts currently will reduce future collections when the HCC relicensing costs are approved for recovery in base rates. As of December 31, 2018, Idaho Power's regulatory liability for collection of AFUDC relating to the HCC was $135 million. In addition to the discussion below, refer to "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 environmental impact statement (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 FERC may require an additional, updated EIS prior to the issuance of a new license for the HCC. 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 the 2016 Section 401 certification application process, Oregon required Idaho Power to comply with fish passage and reintroduction conditions. Idaho's water quality certification, however, provides that Idaho Power shall take no action that may result in the reintroduction or establishment of spawning populations of any fish species into Idaho's waters without consultation with and express approval of the State of Idaho. In November 2016, Idaho Power filed a petition with the FERC requesting that the FERC resolve the conflict between Oregon's and Idaho's conditions and declare that the Federal Power Act (FPA) pre-empts the Oregon state law. In January 2017, the FERC issued an order denying Idaho Power’s petition, stating that the petition for a declaratory order was premature, cannot realistically be considered separately from the issue of the states’ certification authority under the CWA Section 401, and raises issues that are beyond the FERC’s authority to decide. In February 2017, Idaho Power sought rehearing before the FERC on the January 2017 order, which the FERC denied. In February 2018, Idaho Power filed an appeal of the FERC's January 2017 order with the D.C. Circuit Court, which is pending.

In April 2017, the governors of Oregon and Idaho jointly requested that Idaho Power withdraw and resubmit its Section 401 certification applications in both states to allow the states additional time to negotiate a potential resolution of the disputed issues. As of June 2018, the states had not resolved their differences, requiring Idaho Power to again withdraw and resubmit its Section 401 certification applications in both states. In December 2018, the states of Idaho and Oregon, along with Idaho Power, reached a proposed settlement that requires Idaho Power to increase the number of Chinook salmon it releases each year through expanded hatchery production. Additionally, Idaho Power is required to fund a total of $12 million of research and water quality improvements in the HCC, over a 20-year period following the issuance of the license. These measures are in exchange for Oregon removing the fish passage requirement from the Oregon 401 certification for at least the first 20 years after final license issuance. Idaho Power estimates that the combined cost of the mandated water quality improvements and expanded hatchery production is $20 million over the term of the new license. Idaho and Oregon draft 401 certifications were released for public comment in December 2018. After the public comment period closes in February 2019, Idaho Power anticipates the states will evaluate the comments and draft final 401 certifications, which must be completed by June 2019 for the current cycle.

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. 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 construction of new aerated runners at the Brownlee project (part of the HCC) at an estimated cost of $59 million. Three of four units were installed by the end of 2018 and Idaho Power plans to install the final unit in 2019. Other measures that have been proposed or considered have included modification of spillways at the three dams in the HCC 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.

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 $30 million to $40 million until issuance of the license, which Idaho Power estimates will occur no earlier than 2022. In December 2016, Idaho Power filed an application with the IPUC requesting a determination that Idaho Power's expenditures of $220.8 million through year-end 2015 on relicensing of the HCC were prudently incurred, and thus eligible for future inclusion in retail rates in a future rate proceeding. In December 2017, Idaho Power filed with the IPUC a settlement stipulation signed by Idaho Power, the IPUC Staff, and a third party intervenor recognizing that a total of $216.5 million in expenditures were reasonably incurred, and therefore should be eligible for inclusion in customer rates at a later date. As a result of filing the settlement stipulation, Idaho Power recorded a $5.0 million pre-tax charge in 2017, which included $4.3 million for cost incurred through 2015, as well as $0.7 million related to associated costs incurred in 2016 and 2017. Of the $5.0 million pre-tax charge in 2017, $2.5 million was recorded as Other O&M expense and $2.5 million was recorded as a reduction to AFUDC. In April 2018, the IPUC issued an order approving the settlement stipulation as filed with the IPUC and determined the associated costs to be reasonably and prudently incurred.

Renewable Energy Standards and Contracts

Renewable Portfolio Standards: Many states have enacted legislation that would require electric utilities to obtain a specified percentage of their electricity from renewable sources. These requirements are commonly referred to as a "renewable portfolio standard" or "RPS." However, as of the date of this report no State of Idaho RPS is in effect. Idaho Power will be required to comply with either 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 RECs obtained from the purchase of energy 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 percent with customers in the Idaho jurisdiction) of those proceeds through the PCA. For the years ended December 31, 2018, 2017, and 2016, Idaho Power's REC sales totaled $2.9 million, $2.3 million, and $1.0 million, respectively.

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 2012 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 power cost adjustment mechanisms.

Renewable and Other Energy Contracts: Idaho Power has contracts for the purchase of electricity produced by third-party owned generation facilities, most of which produce energy with the use of renewable generation sources such as wind, solar, biomass, small hydroelectric and geothermal. The majority of these contracts are entered into as mandatory purchases under PURPA. As of December 31, 2018, Idaho Power had contracts to purchase energy from 127 on-line PURPA projects. An additional three contracts are with non-PURPA projects, including the Elkhorn Valley wind project with a 101-MW nameplate capacity. The following table sets forth, as of December 31, 2018, the resource type and nameplate capacity of Idaho Power's signed agreements for energy purchases from PURPA and non-PURPA generating facilities. These agreements have original contract terms ranging from one to 35 years.

Resource Type	Total On-line (MW)	Under Contract but not yet On-line (MW)	Total Projects under Contract (MW)
PURPA:			
Wind	627	—	627
Solar	290	27	317
Hydroelectric	146	2	148
Other	56	—	56
Total PURPA	1,119	29	1,148
Non-PURPA:			
Wind	101	—	101
Geothermal	35	—	35
Total non-PURPA	136	—	136

The projects not yet on-line include one hydroelectric project and five solar projects that are scheduled to be on-line in 2019.

ENVIRONMENTAL MATTERS

Overview

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 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 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 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. The decision to pursue an end to participation in coal-fired operations at the Valmy Plant was also based primarily on the economics of operating the plant. Additionally, in light of the uncertainty resulting from pending environmental regulation and the substantial estimated cost of selective catalytic reduction equipment

(SCR) installation, Idaho Power continues to assess whether to move forward with the installation of SCR on units 1 and 2 at the Jim Bridger power plant. Beyond 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 2018 to 2020. Given the uncertainty of future environmental regulations and technological advances, Idaho Power is unable to predict its environmental-related expenditures beyond 2020, though they could be substantial. Furthermore, several executive orders issued in 2017 and 2018 concerning environmental regulations, as described below, could result in significant changes in, and uncertainty with respect to, legislation, regulation, and government policy regarding environmental matters. For example, in August 2017, an executive order was issued to accelerate federal agencies' environmental review and permitting for major infrastructure projects. The outcome of federal agencies' review of regulations covered by executive orders is difficult to predict. Changes to or elimination of regulations may lower Idaho Power's costs of operating and maintaining fossil fuel-fired generation plants and transmission lines, due to the reduction of potential environmental infrastructure upgrades or reduction or elimination of permitting requirements. Executive orders resulting in modifications to federal regulations could, on the other hand, be affected by Congressional action and challenged in court. Further, state and local governmental authorities could choose to replace the federal regulations or bolster environmental compliance and enforcement efforts at the local level, and therefore, Idaho Power is uncertain whether and to what extent the orders could affect its operations and environmental-related expenditures. Idaho Power plans to continue to monitor actions associated with or resulting from executive orders.

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.

In July 2018, the USFWS and the NMFS issued three proposals to revise ESA regulations (2018 ESA Proposals) related to the process and standards for listing species and designating critical habitat, the process for consultations with federal agencies under Section 7 of the ESA (including the definition of "destructive or adverse modification" of designated critical habitat), and the scope of protection of threatened species. Idaho Power believes that if the 2018 ESA Proposals are promulgated, the regulations could reduce Idaho Power's obligations for mitigation under the ESA related to various construction and relicensing projects. Furthermore, in November 2018, the U.S. Supreme Court held that an area is eligible for designation as a critical habitat under the ESA only if it is also "habitat" for the species as defined in the statute, which generally means the area can support the species without modification, and as part of the designation, the USFWS must also consider the costs compared to the benefits of such designation. Idaho Power believes this ruling may limit the number of areas designated as critical habit and could also reduce Idaho Power's obligations for mitigation under the ESA.

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. 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.

Developments in Regulation of Sage Grouse Habitat: In February 2016, a lawsuit was filed in the U.S. District Court of Idaho challenging the BLM's sage grouse resource management and land use plan revisions that became effective in 2015 under the Federal Land Policy and Management Act. The lawsuit challenges the plans and associated environmental impact statements across the sage grouse range and alleges that the plans fail to ensure that sage grouse populations and habitats will be protected and restored in accordance with the best available science and legal mandates. Further, the complaint challenges certain exemptions provided for the Boardman-to-Hemingway and Gateway West transmission line projects. Idaho Power has intervened in the proceedings in an effort to support the exemptions provided for in the BLM's plans. If the exemptions are overturned, Idaho Power may be required to re-route the projects, which could lead to substantially higher construction and permitting costs and could delay construction.

In May 2016, a separate lawsuit was filed in the U.S. District Court of North Dakota, challenging the BLM's sage grouse resource management and land use plan revisions, including the exemptions provided for the Boardman-to-Hemingway and Gateway West transmission line projects. In October 2016, the plaintiffs amended their complaint to no longer challenge the exemptions; however, in December 2016, the North Dakota court transferred claims challenging certain Idaho land use plan amendments to the U.S. District Court for the District of Columbia. Idaho Power is participating in the proceedings in an effort to protect its interests.

In June 2017, the Secretary of the Interior issued an order directing the BLM to review the 2015 sage grouse resource management and land use plan revisions and to identify provisions that may require modification or rescission to address energy and other development of public lands. In December 2018, the BLM issued draft resource management plan amendments and a final environmental impact statements to modify the 2015 sage grouse plans to better align the plan with state plans, conservation measures and the Department of the Interior and BLM policy. As of the date of this report, the above lawsuits are stayed as the parties and the courts have agreed that the processes initiated by the BLM may result in further administrative actions that could remove the need for the lawsuits.

ESA Issues Related to Specific Projects:

<u>Hells Canyon Relicensing Project</u>: 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 2019 is unlikely.

<u>Boardman-to-Hemingway and Gateway West Transmission Projects</u>: In August 2016, the USFWS re-instated the threatened species status of slickspot peppergrass. Most of the species are located on federal land. Idaho Power expects the listing of the slickspot peppergrass and its existence within or near the proposed routes for the Boardman-to-Hemingway and Gateway West transmission line projects to continue to impact the cost and timing of permitting and construction of the projects, as it requires an ESA Section 7 consultation. The USFWS has also indicated it intends to designate critical habitat for the species. If critical habitat is designated within the vicinity of the transmission line projects, Idaho Power expects that the designation could increase the cost of obtaining permits for the projects and could further delay the in-service date of the projects.

Endangered Species Act and National Environmental Policy Act Developments: In May 2016, the United States District Court for the District of Oregon issued an opinion finding that in the context of hydroelectric facilities owned and operated by the U.S. Army Corps of Engineers and located on the lower Snake River, National Oceanic and Atmospheric Administration's National Marine Fisheries Service (NOAA Fisheries) violated the ESA by using improper standards, failing to consider adequately the impact of climate change on habitat conditions, and placing undue reliance on unproven, future federal habitat conservation measures, particularly to the degree that the success of the measures could be undermined by climate change. The court also found that other federal agencies violated the National Environmental Policy Act (NEPA) by failing to prepare a comprehensive environmental impact statement on implementation of the conservation measures ordered by NOAA Fisheries, including analysis of the measures directed by NOAA Fisheries and other reasonable alternatives. The court’s opinion and its emphasis on a climate change-driven analysis element, if generalized to other situations, could require ESA-driven avoidance, minimization, and compensatory mitigation efforts to incorporate surplus measures to ensure species’ protection, which could result in considerable increases in cost beyond the cost of additional analysis in the NEPA process. In September 2016, federal agencies initiated an environmental impact statement process to examine hydroelectric dams on the lower Snake River, which Idaho Power expects will take place over a five-year period. None of Idaho Power's hydroelectric facilities are included in the studies.

Climate Change and the Regulation of Greenhouse Gas 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, wildfires, drought, and other natural phenomena and natural disasters could increase service interruptions, outages, maintenance costs, system damage, liability, 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 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, most notably 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 continued low natural gas prices that decrease the cost to operate natural gas-fired power plants. As a result, Idaho Power plans to end its participation in coal-fired operations at the Valmy Plant units 1 and 2 in 2019 and 2025, respectively, and to cease coal-fired operations at the Boardman power plant no later than December 31, 2020.

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 condition, 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; Clean Power Plan: The U.S. Environmental Protection Agency (EPA) has been 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. While the rule is 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 GHG from existing fossil fuel-fired electric generating units (EGUs). The proposed rule was intended to achieve a 30 percent reduction in CO_2 emissions from the power sector by 2030. In August 2015, the EPA released the final rule under Section 111(d) of the CAA, referred to as the Clean Power Plan (CPP), which required states to adopt plans to collectively reduce 2005 levels of power sector CO_2 emissions by 32 percent by the year 2030. The final rule provided states until September 2018 to submit implementation plans, phasing in several compliance periods beginning in 2022 and achieving the final emissions goals by 2030. In August 2018, the EPA proposed the Affordable Clean Energy (ACE) rule to replace the CPP under Section 111(d) of the CAA for existing electric utility generating units. The new proposed rule is limited to reduction and compliance measures that occur at the physical location of each plant, removing the proposal to require reductions outside the boundaries of plants. The ACE rule also provides for more state-specific control over implementation of the rule to address greenhouse gas emissions from existing coal-fired power plants, with a focus on state evaluation of improvement potential, technical feasibility, applicability, and remaining useful life of each unit. Because the rule is premised on state implementation plans, the terms of which Idaho Power does not control, and due to the existing and potential changes in legislation, regulation, and government policy with respect to environmental matters as a result of the presidential administration's executive orders and the EPA's proposal to repeal and replace the CPP discussed above, as of the date of this report and in light of these executive actions, Idaho Power is uncertain whether and to what extent the replacement CPP may impact its operations in the near term.

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.

In Oregon, legislation referred to as the Oregon Clean Electricity and Coal Transition Plan was enacted in March 2016, and requires certain Oregon utilities to remove coal-fired generation from their Oregon retail rates by 2030. Oregon utilities would be permitted to sell the output of coal-fired plants into the wholesale market or reallocate such plants to other states. To the extent Idaho Power is subject to the legislation, it plans to seek recovery, through the ratemaking process, of operating and capitalized costs related to its coal-fired generation assets and removal of any of those assets from Oregon rate base.

The State of Idaho has not passed legislation specifically regulating GHGs. 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), New Source Review / Prevention of Significant Deterioration Rules, and the Regional Haze Rule.

MATS Implementation: The final MATS rule under the CAA, previously referred to as the Utility Maximum Achievable Control Technology 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. In August 2018, the EPA began reconsidering the justification behind the MATS rule and reviewing the regulations emissions standards. Idaho Power believes that as of the date of this report, its jointly-owned coal-fired plants are in compliance with the MATS rule, and does not expect the EPA's review of the MATS rule to have a significant impact on Idaho Power's operations or financial results.

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, NO_2, and SO_2. 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_2*: In 2010, the EPA adopted a new NAAQS for NO_2 at a level of 100 parts per billion averaged over a 1-hour period. In 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_2. The EPA indicated it would 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_2. 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.

- *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. Since January 2018, the EPA has finalized designations of "unclassifiable/attainment" for SO_2 for all areas in which Idaho Power owns or has an interest in a natural gas or coal-fired power plant.

- *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. In October 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. Since January 2018, the EPA has finalized designations for all of the counties in which Idaho Power owns or has an interest in a natural gas or coal-fired power plant and determined that they meet the standard.

As of the date of this report and based on the EPA designations described above, Idaho Power does not expect these standards to significantly impact its operations or materially increase Idaho Power's capital and operating costs.

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 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 required that PacifiCorp install SCR equipment for nitrogen oxide (NO_x) control at Jim Bridger units 3 and 4 by December 31, 2015 and December 31, 2016, respectively, which has been completed, 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, which was submitted in December 2017. Idaho Power is assessing whether to move forward with installation of SCR equipment at units 1 and 2. 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. In January 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 regional haze 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.

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 (WOTUS Rule). Idaho Power believes that the final rule potentially expanded 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. The WOTUS Rule was widely challenged in both federal district and circuit courts. The State of Idaho, and several other parties, challenged the rule in North Dakota federal court. That court held that it had jurisdiction and enjoined the implementation of the WOTUS Rule. In February 2017, President Trump issued an executive order directing the EPA and the U.S. Army Corps of Engineers to rescind the WOTUS Rule. In July 2017, the EPA and the U.S. Army Corps of Engineers issued a notice of their intent to rescind and replace the definition of "waters of the United States" under the CWA, which Idaho Power expects would reduce the number of waters in Idaho Power's service area subject to the WOTUS Rule. In November 2017, the EPA issued a notice that it will delay the effectiveness of the WOTUS Rule until 2020 while the U.S. Army Corps of Engineers considers a replacement rule. In January 2018, the U.S. Supreme Court issued a unanimous ruling that challenges to the WOTUS Rule must begin with the federal district courts, effectively negating a nationwide stay issued by the Sixth Circuit in 2016. However, because the State of Idaho remains a party to the federal court action in North Dakota, that court's enjoinder remains in effect, meaning the WOTUS Rule currently does not apply to actions brought in Idaho. In July 2018, the EPA and the U.S. Army Corps of Engineers issued a supplemental notice seeking additional comment on their 2017 proposal to repeal the definition of the term WOTUS Rule under the CWA. In August 2018, the U.S. District Court for the District of South Carolina issued a nationwide injunction on the EPA's suspension of the WOTUS Rule, resulting in the WOTUS Rule taking effect in twenty-two states and Washington D.C. The WOTUS Rule does not currently apply in twenty-eight states, including Idaho, and litigation over both the WOTUS Rule and the EPA's suspension of the WOTUS Rule continues. In December 2018, the EPA and U.S. Army Corps of Engineers proposed a rule to significantly limit the definition of "waters of the United States" under the CWA.

Idaho Power has analyzed the WOTUS Rule and expects that, even if the WOTUS Rule is reinstated in Idaho, while it may cause Idaho Power to incur additional permitting, regulatory requirements, 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. Similarly, because the CWA, as interpreted even prior to the WOTUS Rule, applies to most of Idaho Power's facilities, including its hydroelectric plants, Idaho Power does not expect this proposal to have a material benefit to Idaho Power's operations or financial condition.

CWA Matters Related to Hydroelectric Relicensing: 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.

Review of Federal Coal Leases

In January 2016, the Secretary of the U.S. Department of the Interior issued an order directing the BLM to prepare a Programmatic Environmental Impact Statement (PEIS) to analyze potential reforms to the federal coal lease program and placed a moratorium on new federal coal leasing, with limited exceptions, pending completion of the PEIS. In January 2017, the Secretary of the Department of the Interior ordered a cessation of all work on the PEIS and in March 2017 lifted the moratorium on new federal coal leases. As of the date of this report, 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, the lifting of the moratorium could increase the availability of BCC's coal resources and lower the cost of leases for those coal resources.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

When preparing financial statements in accordance with the accounting principles generally accepted in the United States of America (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 area 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 approximately $1.2 billion of regulatory assets and $0.8 billion of regulatory liabilities at December 31, 2018.

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, which could have a material effect on Idaho Power’s financial condition or results of operations.

Refer to Note 3 - “Regulatory Matters” to the consolidated financial statements included in this report for additional information relating to regulatory matters.

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 records 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 recorded 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 recorded 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, and two unfunded nonqualified deferred compensation plan for certain senior management employees and directors called the Security Plan for Senior Management Employees I and Security Plan for Senior Management Employees II (together, 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 capital markets 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, 2018, with maturities matching the projected cash outflows of the plans. Based on the results of this analysis, the discount rate used to calculate the 2019 pension expense will be increased to 4.55 percent from the 3.95 percent used in 2018.

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 2019 pension expense will be 7.5 percent, the same assumption as was used for 2018.

Gross net periodic pension and other postretirement benefit cost for these plans totaled $51.2 million, $50.4 million, and $51.8 million for the years ended December 31, 2018, 2017, and 2016, respectively, including amounts deferred as regulatory assets (see discussion below) and amounts allocated to capitalized labor. For 2019, gross pension and other postretirement benefit costs are expected to total approximately $51.4 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	
	2019	**2018**	**2019**	**2018**
	(millions of dollars)			
Effect of 0.5% rate increase on net periodic benefit cost	$ (7.0)	$ (7.9)	$ (3.5)	$ (3.7)
Effect of 0.5% rate decrease on net periodic benefit cost	7.8	8.8	3.4	3.6

Additionally, a 0.5 percent increase in the plans' discount rates would have resulted in a $76.2 million decrease in the combined benefit obligations of the plans as of December 31, 2018. A 0.5 percent decrease in the plans' discount rates would have resulted in an $85.7 million increase in the combined benefit obligations of the plans as of December 31, 2018.

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, 2018, a total of $148 million of expense was deferred as a regulatory asset. Approximately $23 million is expected to be deferred in 2019. Idaho Power recorded pension expense on its consolidated statements of income related to its tax-qualified defined benefit pension plan of approximately $19 million in 2018, 2017, and 2016.

Refer to Note 12 – “Benefit Plans” to the consolidated financial statements included in this report for additional information relating to pension and postretirement benefit plans.

RECENTLY ISSUED ACCOUNTING PRONOUNCEMENTS

For a listing of new and recently adopted accounting standards, see Note 1 - "Summary of Significant Accounting Policies" to the notes to the consolidated financial statements included in this report.

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, 2018. IDACORP and Idaho Power have 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, 2018, IDACORP and Idaho Power had no net floating rate debt, as the carrying value of short-term investments exceeded the carrying value of outstanding variable-rate debt.

***Fixed Rate Debt*:** As of December 31, 2018, both IDACORP and Idaho Power had $1.8 billion in fixed rate debt, with a fair market value of approximately $1.9 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 $276.8 million if market interest rates were to decline by one percentage point from their December 31, 2018, 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 power cost adjustment 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), comprises 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 and associated standards require 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 the power supply unit for consistency and compliance with the Policy and associated standards. 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, 2018, Idaho Power had no performance assurance collateral posted related to these contracts. 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, 2018, the amount of collateral that could be requested upon a downgrade to below investment grade was approximately $10.5 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 12 - "Benefit Plans" to the consolidated financial statements included in this report.

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,		
	2018	2017	2016
	(thousands of dollars except for per share amounts)		
Operating Revenues:			
Electric utility revenues	$ 1,366,582	$ 1,344,893	$ 1,259,353
Other	4,170	4,593	2,667
Total operating revenues	1,370,752	1,349,486	1,262,020
Operating Expenses:			
Electric utility:			
Purchased power	293,814	248,950	245,764
Fuel expense	133,198	145,829	179,491
Power cost adjustment	42,106	52,024	(5,330)
Other operations and maintenance	364,456	346,695	349,290
Energy efficiency programs	35,703	39,241	33,754
Depreciation	165,190	162,091	143,661
Taxes other than income taxes	34,792	34,089	32,823
Total electric utility expenses	1,069,259	1,028,919	979,453
Other	4,571	5,022	(1,015)
Total operating expenses	1,073,830	1,033,941	978,438
Operating Income	296,922	315,545	283,582
Allowance for Equity Funds Used During Construction	24,353	20,784	22,031
Earnings of Unconsolidated Equity-Method Investments	12,449	11,374	12,871
Other Expense, Net	(2,867)	(2,109)	(1,932)
Interest Expense:			
Interest on long-term debt	84,408	81,198	81,956
Other interest	11,691	11,242	10,273
Allowance for borrowed funds used during construction	(10,151)	(8,694)	(10,194)
Total interest expense, net	85,948	83,746	82,035
Income Before Income Taxes	244,909	261,848	234,517
Income Tax Expense	17,386	48,660	36,429
Net Income	227,523	213,188	198,088
Adjustment for (income) loss attributable to noncontrolling interests	(722)	(769)	200
Net Income Attributable to IDACORP, Inc.	$ 226,801	$ 212,419	$ 198,288
Weighted Average Common Shares Outstanding - Basic (000's)	50,432	50,361	50,298
Weighted Average Common Shares Outstanding - Diluted (000's)	50,510	50,424	50,373
Earnings Per Share of Common Stock:			
Earnings Attributable to IDACORP, Inc. - Basic	$ 4.50	$ 4.22	$ 3.94
Earnings Attributable to IDACORP, Inc. - Diluted	$ 4.49	$ 4.21	$ 3.94

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Statements of Comprehensive Income

	Year Ended December 31,		
	2018	**2017**	**2016**
	(thousands of dollars)		
Net Income	$ 227,523	$ 213,188	$ 198,088
Other Comprehensive Income:			
Unfunded pension liability adjustment, net of tax of $2,815, $(1,555), and $253	8,120	(5,990)	394
Total Comprehensive Income	235,643	207,198	198,482
Comprehensive (income) loss attributable to noncontrolling interests	(722)	(769)	200
Comprehensive Income Attributable to IDACORP, Inc.	$ 234,921	$ 206,429	$ 198,682

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Balance Sheets

	December 31, 2018	December 31, 2017
	(in thousands)	
Assets		
Current Assets:		
Cash and cash equivalents	$ 267,492	$ 76,649
Receivables:		
Customer (net of allowance of $1,725 and $2,013, respectively)	77,178	75,249
Other (net of allowance of $264 and $180, respectively)	7,476	30,438
Income taxes receivable	4,356	8,147
Accrued unbilled revenues	69,318	75,120
Materials and supplies (at average cost)	54,987	55,745
Fuel stock (at average cost)	47,979	56,638
Prepayments	16,492	16,984
Current regulatory assets	48,707	48,613
Other	3,655	18
Total current assets	597,640	443,601
Investments	101,178	115,698
Property, Plant and Equipment:		
Utility plant in service	6,103,856	5,906,162
Accumulated provision for depreciation	(2,210,781)	(2,098,274)
Utility plant in service - net	3,893,075	3,807,888
Construction work in progress	480,259	452,424
Utility plant held for future use	4,751	8,075
Other property, net of accumulated depreciation	17,650	15,488
Property, plant and equipment - net	4,395,735	4,283,875
Other Assets:		
Company-owned life insurance	59,852	59,323
Regulatory assets	1,165,467	1,083,483
Other	62,882	59,425
Total other assets	1,288,201	1,202,231
Total	$ 6,382,754	$ 6,045,405

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Balance Sheets

	December 31,	
	2018	**2017**
	(in thousands)	
Liabilities and Equity		
Current Liabilities:		
Accounts payable	$ 110,824	$ 90,277
Taxes accrued	12,009	11,075
Interest accrued	23,622	22,379
Accrued compensation	55,121	47,018
Current regulatory liabilities	25,883	1,404
Advances from customers	20,037	18,414
Other	11,096	10,182
Total current liabilities	258,592	200,749
Other Liabilities:		
Deferred income taxes	699,878	660,940
Regulatory liabilities	738,994	698,044
Pension and other postretirement benefits	431,475	438,869
Other	43,216	44,566
Total other liabilities	1,913,563	1,842,419
Long-Term Debt	1,834,788	1,746,123
Commitments and Contingencies		
Equity:		
IDACORP, Inc. shareholders' equity:		
Common stock, no par value (120,000 shares authorized; shares issued 50,420)	863,593	857,207
Retained earnings	1,531,543	1,426,528
Accumulated other comprehensive loss	(22,844)	(30,964)
Treasury stock (27 and 28 shares at cost, respectively)	(1,932)	(1,386)
Total IDACORP, Inc. shareholders' equity	2,370,360	2,251,385
Noncontrolling interests	5,451	4,729
Total equity	2,375,811	2,256,114
Total	$ 6,382,754	$ 6,045,405

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Statements of Cash Flows

	Year Ended December 31, 2018	2017	2016
	(thousands of dollars)		
Operating Activities:			
Net income	$ 227,523	$ 213,188	$ 198,088
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	169,120	165,933	147,294
Deferred income taxes and investment tax credits	11,292	33,245	35,732
Changes in regulatory assets and liabilities	48,392	57,131	(5,650)
Pension and postretirement benefit plan expense	32,256	28,911	29,581
Contributions to pension and postretirement benefit plans	(45,899)	(46,589)	(45,301)
Earnings of unconsolidated equity-method investments	(12,449)	(11,374)	(12,871)
Distributions from unconsolidated equity-method investments	31,115	24,975	25,641
Allowance for equity funds used during construction	(24,353)	(20,784)	(22,031)
Gain on sale of investments and assets	(155)	(131)	(103)
Other non-cash adjustments to net income, net	9,152	8,454	5,108
Change in:			
Accounts receivable	729	1,045	(6,315)
Accounts payable and other accrued liabilities	29,666	(17,208)	13,300
Taxes accrued/receivable	4,725	4,361	662
Other current assets	12,707	2,814	(10,887)
Other current liabilities	6,848	1,017	(3,283)
Other assets	(7,488)	(8,734)	(3,764)
Other liabilities	(1,555)	(1,093)	(1,006)
Net cash provided by operating activities	491,626	435,161	344,195
Investing Activities:			
Additions to property, plant and equipment	(277,853)	(285,488)	(296,950)
Payments received from transmission project joint funding partners	21,587	6,074	7,586
Purchase of available-for-sale securities	(11,390)	(11,356)	(14,917)
Proceeds from sale of available-for-sale securities	5,007	4,989	15,693
Purchase of life insurance investment	—	—	(10,000)
Other	4,472	5,340	4,655
Net cash used in investing activities	(258,177)	(280,441)	(293,933)
Financing Activities:			
Issuance of long-term debt	220,000	—	120,000
Retirement of long-term debt	(130,000)	(1,064)	(101,064)
Dividends on common stock	(121,421)	(113,127)	(104,984)
Net change in short-term borrowings	—	(21,800)	1,800
Acquisition of treasury stock	(3,614)	(3,212)	(3,329)
Make-whole premium on retirement of long-term debt	(4,607)	—	(13,895)
Other	(2,964)	(348)	(2,112)
Net cash used in financing activities	(42,606)	(139,551)	(103,584)
Net increase (decrease) in cash and cash equivalents	190,843	15,169	(53,322)
Cash and cash equivalents at beginning of the year	76,649	61,480	114,802
Cash and cash equivalents at end of the year	$ 267,492	$ 76,649	$ 61,480
Supplemental Disclosure of Cash Flow Information:			
Cash paid during the year for:			
Income taxes	$ 5,272	$ 14,742	$ 3,302
Interest (net of amount capitalized)	$ 80,951	$ 80,004	$ 78,334
Non-cash investing activities:			
Additions to property, plant and equipment in accounts payable	$ 29,528	$ 33,220	$ 34,603

The accompanying notes are an integral part of these statements.

IDACORP, Inc.
Consolidated Statements of Equity

	Year Ended December 31,		
	2018	2017	2016
	(thousands of dollars)		
Common Stock:			
Balance at beginning of year	$ 857,207	$ 851,833	$ 849,112
Cumulative effect of change in accounting principle	—	—	234
Share-based compensation expense	9,362	7,384	5,561
Treasury shares issued	(3,068)	(2,069)	(3,143)
Other	92	59	69
Balance at end of year	863,593	857,207	851,833
Retained Earnings:			
Balance at beginning of year	1,426,528	1,323,198	1,230,105
Cumulative effect of change in accounting principle	—	4,092	(234)
Net income attributable to IDACORP, Inc.	226,801	212,419	198,288
Common stock dividends ($2.40, $2.24, and $2.08 per share, respectively)	(121,786)	(113,181)	(104,961)
Balance at end of year	1,531,543	1,426,528	1,323,198
Accumulated Other Comprehensive (Loss) Income:			
Balance at beginning of year	(30,964)	(20,882)	(21,276)
Cumulative effect of change in accounting principle	—	(4,092)	—
Unfunded pension liability adjustment (net of tax)	8,120	(5,990)	394
Balance at end of year	(22,844)	(30,964)	(20,882)
Treasury Stock:			
Balance at beginning of year	(1,386)	(243)	(57)
Issued	3,068	2,069	3,143
Acquired	(3,614)	(3,212)	(3,329)
Balance at end of year	(1,932)	(1,386)	(243)
Total IDACORP, Inc. shareholders' equity at end of year	2,370,360	2,251,385	2,153,906
Noncontrolling Interests:			
Balance at beginning of year	4,729	3,960	4,160
Net income (loss) attributable to noncontrolling interests	722	769	(200)
Balance at end of year	5,451	4,729	3,960
Total equity at end of year	$ 2,375,811	$ 2,256,114	$ 2,157,866

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Statements of Income

	Year Ended December 31,		
	2018	**2017**	**2016**
	(thousands of dollars)		
Operating Revenues	$ 1,366,582	$ 1,344,893	$ 1,259,353
Operating Expenses:			
Operation:			
Purchased power	293,814	248,950	245,764
Fuel expense	133,198	145,829	179,491
Power cost adjustment	42,106	52,024	(5,330)
Other operations and maintenance	364,456	346,695	349,290
Energy efficiency programs	35,703	39,241	33,754
Depreciation	165,190	162,091	143,661
Taxes other than income taxes	34,792	34,089	32,823
Total operating expenses	1,069,259	1,028,919	979,453
Income from Operations	297,323	315,974	279,900
Other Income (Expense):			
Allowance for equity funds used during construction	24,353	20,784	22,031
Earnings of unconsolidated equity-method investments	10,712	9,267	10,855
Other expense, net	(5,851)	(4,756)	(4,547)
Total other income	29,214	25,295	28,339
Interest Charges:			
Interest on long-term debt	84,408	81,198	81,956
Other interest	11,634	11,156	10,050
Allowance for borrowed funds used during construction	(10,151)	(8,694)	(10,194)
Total interest charges	85,891	83,660	81,812
Income Before Income Taxes	240,646	257,609	226,427
Income Tax Expense	18,312	51,262	37,185
Net Income	$ 222,334	$ 206,347	$ 189,242

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Statements of Comprehensive Income

	Year Ended December 31,		
	2018	**2017**	**2016**
	(thousands of dollars)		
Net Income	$ 222,334	$ 206,347	$ 189,242
Other Comprehensive Income:			
Unfunded pension liability adjustment, net of tax of $2,815, $(1,555), and $253	8,120	(5,990)	394
Total Comprehensive Income	$ 230,454	$ 200,357	$ 189,636

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Balance Sheets

	December 31,	
	2018	**2017**
	(in thousands)	
Assets		
Electric Plant:		
In service (at original cost)	$ 6,103,856	$ 5,906,162
Accumulated provision for depreciation	(2,210,781)	(2,098,274)
In service - net	3,893,075	3,807,888
Construction work in progress	480,259	452,424
Held for future use	4,751	8,075
Electric plant - net	4,378,085	4,268,387
Investments and Other Property	90,019	99,904
Current Assets:		
Cash and cash equivalents	165,460	44,646
Receivables:		
Customer (net of allowance of $1,725 and $2,013, respectively)	77,178	75,249
Other (net of allowance of $264 and $180, respectively)	7,206	30,274
Income taxes receivable	11,829	26,492
Accrued unbilled revenues	69,318	75,120
Materials and supplies (at average cost)	54,987	55,745
Fuel stock (at average cost)	47,979	56,638
Prepayments	16,374	16,866
Current regulatory assets	48,707	48,613
Other	3,655	18
Total current assets	502,693	429,661
Deferred Debits:		
Company-owned life insurance	59,852	59,323
Regulatory assets	1,165,467	1,083,483
Other	58,284	54,677
Total deferred debits	1,283,603	1,197,483
Total	$ 6,254,400	$ 5,995,435

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Balance Sheets

	December 31,	
	2018	**2017**
	(in thousands)	
Capitalization and Liabilities		
Capitalization:		
Common stock equity:		
Common stock, $2.50 par value (50,000 shares authorized; 39,151 shares outstanding)	$ 97,877	$ 97,877
Premium on capital stock	712,258	712,258
Capital stock expense	(2,097)	(2,097)
Retained earnings	1,409,245	1,308,702
Accumulated other comprehensive loss	(22,844)	(30,964)
Total common stock equity	2,194,439	2,085,776
Long-term debt	1,834,788	1,746,123
Total capitalization	4,029,227	3,831,899
Current Liabilities:		
Accounts payable	110,597	89,978
Accounts payable to affiliates	2,088	57,562
Taxes accrued	11,750	10,904
Interest accrued	23,622	22,379
Accrued compensation	54,910	46,832
Current regulatory liabilities	25,883	1,404
Advances from customers	20,037	18,414
Other	10,198	9,556
Total current liabilities	259,085	257,029
Deferred Credits:		
Deferred income taxes	753,239	725,942
Regulatory liabilities	738,994	698,044
Pension and other postretirement benefits	431,475	438,869
Other	42,380	43,652
Total deferred credits	1,966,088	1,906,507
Commitments and Contingencies		
Total	$ 6,254,400	$ 5,995,435

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Statements of Cash Flows

	Year Ended December 31,		
	2018	2017	2016
	(thousands of dollars)		
Operating Activities:			
Net income	$ 222,334	$ 206,347	$ 189,242
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	168,519	165,337	146,694
Deferred income taxes and investment tax credits	(2,272)	(10,875)	25,780
Changes in regulatory assets and liabilities	48,392	57,131	(5,651)
Pension and postretirement benefit plan expense	32,240	28,894	29,597
Contributions to pension and postretirement benefit plans	(45,883)	(46,573)	(45,317)
Earnings of unconsolidated equity-method investments	(10,712)	(9,267)	(10,855)
Distributions from unconsolidated equity-method investments	29,400	23,000	23,716
Allowance for equity funds used during construction	(24,353)	(20,784)	(22,031)
Gain on sale of investments and assets	(155)	(131)	(103)
Other non-cash adjustments to net income, net	(210)	1,069	(454)
Change in:			
Accounts receivable	633	(5,282)	(54)
Accounts payable	(25,532)	38,111	13,308
Taxes accrued/receivable	15,509	(3,601)	(17,299)
Other current assets	12,707	2,812	(10,902)
Other current liabilities	6,822	996	(3,322)
Other assets	(7,488)	(8,734)	(3,764)
Other liabilities	(1,476)	(967)	(829)
Net cash provided by operating activities	418,475	417,483	307,756
Investing Activities:			
Additions to utility plant	(277,823)	(285,471)	(296,948)
Payments received from transmission project joint funding partners	21,587	6,074	7,586
Purchase of available-for-sale securities	(11,390)	(11,356)	(14,917)
Proceeds from the sale of available-for-sale securities	5,007	4,989	15,693
Purchase of life insurance investment	—	—	(10,000)
Other	4,320	5,176	4,511
Net cash used in investing activities	(258,299)	(280,588)	(294,075)
Financing Activities:			
Issuance of long-term debt	220,000	—	120,000
Retirement of long-term debt	(130,000)	(1,064)	(101,064)
Dividends on common stock	(121,791)	(113,284)	(105,121)
Net change in short term borrowings	—	(21,800)	21,800
Make-whole premium on retirement of long-term debt	(4,607)	—	(13,895)
Other	(2,964)	(241)	(2,017)
Net cash used in financing activities	(39,362)	(136,389)	(80,297)
Net increase (decrease) in cash and cash equivalents	120,814	506	(66,616)
Cash and cash equivalents at beginning of the year	44,646	44,140	110,756
Cash and cash equivalents at end of the year	$ 165,460	$ 44,646	$ 44,140
Supplemental Disclosure of Cash Flow Information:			
Cash paid to IDACORP related to income taxes	$ 63,914	$ 12,444	$ 29,341
Cash paid for interest (net of amount capitalized)	$ 80,894	$ 79,918	$ 78,111
Non-cash investing activities:			
Additions to property, plant and equipment in accounts payable	$ 29,528	$ 33,220	$ 34,603

The accompanying notes are an integral part of these statements.

Idaho Power Company
Consolidated Statements of Retained Earnings

	Year Ended December 31,		
	2018	2017	2016
	(thousands of dollars)		
Retained Earnings, Beginning of Year	$ 1,308,702	$ 1,211,547	$ 1,127,426
Net Income	222,334	206,347	189,242
Dividends on Common Stock	(121,791)	(113,284)	(105,121)
Cumulative Effect of Change in Accounting Principle	—	4,092	—
Retained Earnings, End of Year	$ 1,409,245	$ 1,308,702	$ 1,211,547

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 engaged in the generation, transmission, distribution, sales, and purchase of electric energy and capacity with a service area covering approximately 24,000 square miles in southern Idaho and eastern Oregon. Idaho Power is regulated primarily by the state utility regulatory commissions of Idaho and Oregon and the Federal Energy Regulatory Commission (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.

IDACORP's other notable wholly-owned subsidiaries include IDACORP Financial Services, Inc. (IFS), an investor in affordable housing and other real estate investments, and 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).

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, 2018, Marysville had approximately $18 million of assets, primarily a hydroelectric plant, and approximately $8 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 venture. 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 $49.9 million at December 31, 2018, and Idaho Power's maximum exposure to loss is the carrying value, any additional future contributions to BCC, and a $58.4 million guarantee for mine reclamation costs, which is discussed further in Note 10 - "Commitments."

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 4 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 $3.4 million at December 31, 2018.

Ida-West's other investments in PURPA facilities, BCC, and IFS's investments are accounted for under the equity method of accounting (see Note 15 - "Investments").

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 13 - "Property, Plant and Equipment and Jointly-Owned Projects").

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. 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 effects of applying these regulatory accounting principles to Idaho Power’s operations are discussed in more detail in Note 3 - "Regulatory Matters."

Management Estimates

Management makes estimates and assumptions when preparing financial statements in conformity with generally accepted accounting principles. These estimates and assumptions include those related to rate regulation, retirement benefits, contingencies, 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. Accordingly, 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.

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 per month 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, 2018 and 2017. 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

On January 1, 2018, IDACORP and Idaho Power adopted Accounting Standards Update (ASU) 2014-09, *Revenue from Contracts with Customers (Topic 606)*. The adoption did not change the timing or amounts of revenue recognized by IDACORP or Idaho Power. Operating revenues are generally recorded when service is rendered or energy is delivered to customers. Idaho Power accrues estimated unbilled revenues for electric services delivered to customers but not yet billed at year-end. Idaho Power does not report any collections of franchise fees and similar taxes related to energy consumption on the income statement. In addition, regulatory mechanisms in place in Idaho and Oregon affect the reported amount of revenue. The effects of applying these regulatory mechanisms are discussed in more detail in Note 4 - "Revenues."

Property, Plant and Equipment and Depreciation

The cost of utility plant in service represents the original cost of contracted services, direct labor and material, allowance for funds used during construction (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 2.8 percent in 2018, 2.9 percent in 2017, and 2.6 percent in 2016.

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 2018, 2017, or 2016.

Allowance for Funds Used During Construction

AFUDC represents the cost of financing construction projects with borrowed funds and equity funds. With one exception, for the Hells Canyon Complex (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 2018, 2017 and 2016.

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 record 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.

IDACORP and Idaho Power use judgment, estimation, and historical data in developing the provision for income taxes and the reporting of tax-related assets and liabilities, including development of current year tax depreciation, capitalized repair costs, capitalized overheads, and other items. Income taxes can be impacted by changes in tax laws and regulations, interpretations by taxing authorities, changes to accounting guidance, and actions by federal or state public utility regulators. 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.

In compliance with the federal income tax requirements for the use of accelerated tax depreciation, Idaho Power records 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 recorded 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 - "Income Taxes."

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.

Reclassifications

In these consolidated financial statements, certain amounts in prior periods' consolidated financial statements have been reclassified to conform with current period presentation. On IDACORP's and Idaho Power's December 31, 2017, consolidated balance sheets, the "Long-term receivables" balances of $4.3 million and $0.5 million, respectively, which had previously been reported separately, were reclassified to "Other" within "Other Assets" and "Deferred Debits," respectively.

New and Recently Adopted Accounting Pronouncements

Recently Adopted Accounting Pronouncements

In May 2014, the Financial Accounting Standards Board (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 FASB amended certain aspects of ASU 2014-09 to clarify the implementation guidance, including clarifications related to principal versus agent considerations, licensing and identifying performance obligations, narrow scope improvements, and practical expedients. IDACORP and Idaho Power adopted ASU 2014-09 on January 1, 2018, using the modified-retrospective approach as provided for in the standard. The adoption did not change the timing or amounts of revenue currently recognized by the companies, so no cumulative-effect adjustment was required. The adoption did change presentation of revenues on the consolidated statements of income and also added disclosures. To conform with current period presentation, "Electric utility revenues" and "Operating Revenues" on

IDACORP's and Idaho Power's consolidated statements of income, respectively, for the year ended December 31, 2018 and 2017, which had previously been reported separately as "General business," "Off-system sales," and "Other revenues," are no longer reported separately. See Note 4 - "Revenues" for additional information on the disaggregation of revenue and additional disclosures.

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 adopted ASU 2016-01 on January 1, 2018. The adoption did not have a material impact on the companies' financial statements as the companies previously elected the fair value option and reported available-for-sale securities at fair value.

In August 2016, the FASB issued ASU 2016-15, *Statement of Cash Flows (Topic 230) Classification of Certain Cash Receipts and Cash Payments*, to reduce diversity in practice in how certain cash receipts and cash payments are classified in the statement of cash flows. The companies' classification of proceeds from the settlement of corporate-owned life insurance policies and related costs will be classified as investing activities under the new guidance. The new guidance did not affect the companies' presentation of debt prepayment and extinguishment costs, proceeds from the settlement of insurance claims (other than corporate-owned life insurance), and distributions received from equity-method investments. IDACORP and Idaho Power adopted ASU 2016-15 on January 1, 2018, using the retrospective approach as provided for in the standard. To conform with current period presentation, the companies reclassified $3.0 million and $3.6 million of company-owned life insurance proceeds received, for the year ended December 31, 2017 and 2016, respectively, from "Change in accounts receivable" and $0.1 million and $0.1 million of prepaid insurance premiums paid, for the year ended December 31, 2017 and 2016, respectively, from "Change in other assets" (net reclassification of $2.9 million and $3.5 million, respectively) within "Operating Activities" to "Other" within "Investing Activities" on the consolidated statement of cash flows.

In March 2017, the FASB issued ASU 2017-07, *Compensation -- Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost,* which requires employers to disaggregate the service cost component from other components of net periodic benefit costs and to disclose the amounts of net periodic benefit costs that are included in each income statement line item. The standard requires employers to present the service cost component in the same line item as other compensation costs and to present the other components of net periodic benefit cost (which include interest costs, expected return on plan assets, amortization of prior service cost or credits and actuarial gains and losses) separately and outside a subtotal of operating income. In addition, only the service cost component is eligible for capitalization. Idaho Power capitalizes amounts of pension or postretirement costs that are insignificant to the consolidated financial statements. The amendments in ASU 2017-07 are effective for interim and annual reporting periods beginning after December 15, 2017. Entities must use (1) a retrospective transition method to adopt the requirement for separate presentation in the income statement of service costs and other components and (2) a prospective transition method to adopt the requirement to limit the capitalization of benefit costs to the service cost component. IDACORP and Idaho Power adopted ASU 2017-07 on January 1, 2018, and accordingly, have retrospectively adjusted prior periods to reflect the disaggregation of service cost from other components of net periodic benefit costs. The adoption did not have a material impact on the companies' financial statements nor did it affect net income for the year ended December 31, 2018. For IDACORP, for the year ended December 31, 2017 and 2016, $3.0 million and $2.6 million, respectively, were reclassified out of "Other operations and maintenance" and $8.2 million and $9.2 million, respectively, were reclassified out of "Other" operating expenses for a total of $11.2 million and $11.8 million, respectively, reclassified to "Other Expense, Net" to conform to current period presentation. For Idaho Power, for the year ended December 31, 2017 and 2016, $3.0 million and $2.6 million, respectively, was reclassified from "Other operations and maintenance" to "Other expense, net" to conform to current period presentation.

Recent Accounting Pronouncements Not Yet Adopted

In August 2018, the FASB issued ASU 2018-15, *Intangibles—Goodwill and Other—Internal-Use Software (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract*, to provide guidance on implementation costs incurred in a cloud computing arrangement that is a service contract. ASU 2018-15 aligns the accounting for such costs with the guidance on capitalizing costs associated with developing or obtaining internal-use software. The new standard is effective for interim and annual reporting periods beginning after December 15, 2019, with early adoption permitted. IDACORP and Idaho Power are evaluating the impact of ASU 2018-15 on their respective financial statements.

In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842)*, intended to improve financial reporting about leasing transactions. The ASU requires lessees to recognize a right-of-use asset and lease liability on the balance sheet for most leases. In addition, the ASU revises the definition of a lease in regards to when an arrangement conveys the right to control the use of the identified asset under the arrangement, which may result in changes to the classification of an arrangement as a lease. ASU 2016-02 was effective on January 1, 2019, and IDACORP and Idaho Power will record any effects of the adoption in the first quarter of 2019. While IDACORP and Idaho Power are finalizing the assessment of the financial impacts of the adoption, the adoption of ASU 2016-02 will not have a material impact on their respective 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		
	2018	**2017**	**2016**	**2018**	**2017**	**2016**
	(thousands of dollars)					
Federal income tax expense at statutory rate	$ 51,279	$ 91,378	$ 82,151	$ 50,536	$ 90,163	$ 79,250
Change in taxes resulting from:						
AFUDC	(7,246)	(10,318)	(11,278)	(7,246)	(10,318)	(11,278)
Capitalized interest	928	1,513	2,000	928	1,513	2,000
Investment tax credits	(2,929)	(3,081)	(2,922)	(2,929)	(3,081)	(2,922)
Removal costs	(3,471)	(6,280)	(5,559)	(3,471)	(6,280)	(5,559)
Capitalized overhead costs	(6,720)	(11,200)	(10,500)	(6,720)	(11,200)	(10,500)
Capitalized repair costs	(17,850)	(28,700)	(28,000)	(17,850)	(28,700)	(28,000)
Bond redemption costs	(1,029)	—	(4,997)	(1,029)	—	(4,997)
Remeasurement of deferred taxes	(5,411)	1,690	—	(5,664)	1,970	—
State income taxes, net of federal benefit	8,512	8,153	5,071	8,532	8,108	4,880
Depreciation	13,110	18,953	18,673	13,110	18,953	18,673
Excess deferred income tax reversal	(7,289)	—	—	(7,289)	—	—
Share-based compensation	(894)	(1,508)	(1,614)	(883)	(1,483)	(1,583)
Income tax return adjustments	(5,076)	(3,710)	(3,539)	(4,968)	(3,601)	(3,669)
Affordable housing tax credits	(2,560)	(2,559)	(2,579)	—	—	—
Affordable housing investment distributions	(267)	(1,124)	(1,717)	—	—	—
Affordable housing investment amortization	1,519	1,271	1,380	—	—	—
Other, net	2,780	(5,818)	(141)	3,255	(4,782)	890
Total income tax expense	$ 17,386	$ 48,660	$ 36,429	$ 18,312	$ 51,262	$ 37,185
Effective tax rate	7.1%	18.6%	15.5%	7.6%	19.9%	16.4%

The items comprising income tax expense are as follows:

	IDACORP			Idaho Power		
	2018	2017	2016	2018	2017	2016
	(thousands of dollars)					
Income taxes current:						
Federal	$ 5,390	$ 11,726	$ 1,181	$ 24,919	$ 51,575	$ 7,639
State	3,328	5,418	2,158	(2,049)	10,562	3,766
Total	8,718	17,144	3,339	22,870	62,137	11,405
Income taxes deferred:						
Federal	1,649	24,018	33,205	(15,388)	(13,002)	27,506
State	30	(154)	100	5,425	(5,298)	(2,031)
Total	1,679	23,864	33,305	(9,963)	(18,300)	25,475
Investment tax credits:						
Deferred	8,334	10,506	3,227	8,334	10,506	3,227
Restored	(2,929)	(3,081)	(2,922)	(2,929)	(3,081)	(2,922)
Total	5,405	7,425	305	5,405	7,425	305
Affordable housing investments	1,584	227	(520)	—	—	—
Total income tax expense	$ 17,386	$ 48,660	$ 36,429	$ 18,312	$ 51,262	$ 37,185

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

	IDACORP		Idaho Power	
	2018	2017	2018	2017
	(thousands of dollars)			
Deferred tax assets:				
Regulatory liabilities	$ 98,042	$ 98,744	$ 98,042	$ 98,744
Deferred compensation	21,871	21,066	21,826	21,025
Deferred revenue	35,137	31,086	35,137	31,086
Tax credits	100,041	109,673	44,532	44,106
Partnership investments	4,200	3,540	1,086	—
Retirement benefits	91,867	94,493	91,867	94,493
Other	9,299	8,636	9,121	8,435
Total	360,457	367,238	301,611	297,889
Deferred tax liabilities:				
Property, plant and equipment	294,471	306,002	294,471	306,002
Regulatory assets	614,144	584,329	614,144	584,329
Fixed cost adjustment	10,940	8,016	10,940	8,016
Partnership investments	3,875	5,182	—	980
Retirement benefits	108,440	103,407	108,440	103,407
Other	28,465	21,242	26,855	21,097
Total	1,060,335	1,028,178	1,054,850	1,023,831
Net deferred tax liabilities	$ 699,878	$ 660,940	$ 753,239	$ 725,942

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 and are reported as taxes accrued or income taxes receivable, respectively, on the consolidated balance sheets of Idaho Power. See Note 1 - "Summary of Significant Accounting Policies" for further discussion of accounting policies related to income taxes.

Tax Credit Carryforwards

As of December 31, 2018, IDACORP had $60.5 million of general business credit carryforwards for federal income tax purposes and $39.5 million of Idaho investment tax credit carryforward. The general business credit carryforward period expires from 2027 to 2038, and the Idaho investment tax credit expires from 2023 to 2032.

Uncertain Tax Positions

IDACORP and Idaho Power believe that they have no material income tax uncertainties for 2018 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 2018 for federal and 2014-2018 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 2018, the IRS completed its examination of IDACORP's 2017 tax year with no unresolved income tax issues.

Income Tax Reform

In December 2017, the Tax Cuts and Jobs Act was signed into law, which significantly reforms the Internal Revenue Code of 1986, as amended. Effective January 1, 2018, the Tax Cuts and Jobs Act permanently lowers the corporate tax rate to 21 percent from the existing maximum rate of 35 percent, provides for expanded bonus depreciation, limits the deductibility of interest expense, eliminates the alternative minimum tax, repeals the manufacturing deduction, and imposes additional limitations on the deductibility of executive compensation. Public utility companies, such as Idaho Power, retain the deductibility of interest expense and are excluded from the bonus depreciation provisions; however, traditional accelerated tax depreciation methods are still available.

Due to the enactment of the Tax Cuts and Jobs Act and following generally accepted accounting principles, at December 31, 2017, IDACORP and Idaho Power remeasured all deferred income tax assets and liabilities. The effects of these adjustments resulted in a net tax expense for 2017, as shown in the rate reconciliation table above. Also, as shown above, in 2018, a net tax benefit was recognized for the remeasurement of deferred taxes for the adjustment of temporary differences as a result of IDACORP's 2017 consolidated income tax return filings.

Additionally, in 2017, the net deferred tax liabilities at both companies decreased by approximately $672 million. Idaho Power's regulatory asset deferred income tax liability item decreased as the related regulatory asset was reduced in two primary ways: (1) the decrease in the federal income tax rate decreased the future cost to customers for funding the net deferred income tax liabilities resulting from the cumulative impacts of using the flow-through income tax accounting method for regulatory purposes and (2) the decrease in the federal income tax rate also reduced the net-to-gross multiplier that increases the regulatory asset to a revenue requirement carrying value. The change in income tax law also reduced the deferred income tax liability for depreciation-related timing differences under the normalized tax accounting method. As this reduction will flow back to customers in the future under the statutorily prescribed average rate assumption method, it was recorded as a regulatory liability on the consolidated balance sheets of the companies.

On March 12, 2018, Idaho House Bill 463 was enacted which lowered the Idaho state corporate income tax rate from 7.4 percent to 6.925 percent effective January 1, 2018. The Idaho tax rate reduction did not have a material impact on IDACORP's and Idaho Power's 2018 income tax expense or deferred tax asset and liability balances.

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 some expenses and revenues in a different period than when an unregulated enterprise would record those 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, 2018 Earning a Return[1]	As of December 31, 2018 Not Earning a Return	Total as of December 31, 2018	Total as of December 31, 2017
Regulatory Assets:					
Income taxes[2]		$ —	$ 614,144	$ 614,144	$ 584,329
Unfunded postretirement benefits[3]		—	278,674	278,674	280,166
Pension expense deferrals		126,811	21,025	147,836	127,721
Energy efficiency program costs[4]		1,398	—	1,398	6,273
Power supply costs[5]		—	—	—	3,137
Fixed cost adjustment[5]	2019-2020	34,502	8,001	42,503	30,856
Valmy Plant settlements[5]	2019-2028	77,512	—	77,512	44,633
Asset retirement obligations[6]		—	17,655	17,655	15,767
Long-term service agreement	2019-2043	16,095	10,653	26,748	27,907
Other	2019-2055	720	6,984	7,704	11,307
Total		$ 257,038	$ 957,136	$ 1,214,174	$ 1,132,096
Regulatory Liabilities:					
Income taxes[7]		$ —	$ 98,042	$ 98,042	$ 98,744
Depreciation-related excess deferred income taxes[8]		190,062	—	190,062	193,991
Removal costs[6]		—	183,798	183,798	184,993
Investment tax credits		—	92,790	92,790	87,385
Deferred revenue-AFUDC[9]		95,660	39,486	135,146	119,666
Energy efficiency program costs[4]		5,259	—	5,259	408
Power supply costs[5]	2019-2020	35,815	6,507	42,322	5,443
Settlement agreement sharing mechanism[5]	2019-2020	5,025	—	5,025	—
Mark-to-market assets[10]		—	3,700	3,700	22
Other		2,419	6,314	8,733	8,796
Total		$ 334,240	$ 430,637	$ 764,877	$ 699,448

(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 flow-through income tax accounting differences which have a corresponding deferred tax liability disclosed in Note 2 - "Income Taxes."
(3) Represents the unfunded obligation of Idaho Power's pension and postretirement benefit plans, which are discussed in Note 12 - "Benefit Plans."
(4) The energy efficiency asset represents the Oregon jurisdiction balance and the liability represents the Idaho jurisdiction balance.
(5) This item is discussed in more detail in this Note 3 - "Regulatory Matters."
(6) Asset retirement obligations and removal costs are discussed in Note 14 - "Asset Retirement Obligations."
(7) Represents the tax gross-up related to the depreciation-related excess deferred income taxes and investment tax credits included in this table and has a corresponding deferred tax asset disclosed in Note 2 - "Income Taxes."
(8) The Tax Cuts and Jobs Act, enacted on December 22, 2017, reduced the deferred income tax assets and liabilities. For depreciation-related timing differences under the normalized tax accounting method, this reduction will flow back to customers under the statutorily prescribed average rate assumption method.
(9) 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.
(10) Mark-to-market assets and liabilities are discussed in Note 17 - "Fair Value Measurements."

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 mechanisms address the volatility of power supply costs and provide for annual adjustments to the rates charged to its retail customers. The power cost adjustment mechanisms compare Idaho Power's actual net power supply costs (primarily fuel and purchased power less wholesale energy sales) against net power supply costs being recovered in Idaho Power's retail rates. Under the power cost adjustment mechanisms, certain differences between actual net power supply costs incurred by Idaho Power and costs being recovered in retail rates 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. The Idaho deferral period or Idaho-jurisdiction power cost adjustment (PCA) year runs from April 1 through March 31. Amounts deferred during the PCA year are primarily recovered or refunded during the subsequent June 1 through May 31 period.

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 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 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, 2018	$	(30.4)	The $30.4 million total decrease in PCA rates includes a $7.8 million one-time benefit for income tax benefits accrued from January 1 to May 31, 2018, and the income taxes related to Idaho Power's open access transmission tariff (OATT) rate. See "Income Tax Reform - Regulatory Treatment" below for more information.
June 1, 2017	$	10.6	The net increase in PCA rates included an offsetting $13.0 million reduction for the refund of previously collected Idaho energy efficiency rider funds.
June 1, 2016	$	17.3	The net increase in PCA rates included the application of (a) a customer rate credit of $3.2 million for sharing of revenues with customers for the year 2015 under the terms of the October 2014 settlement stipulation, and (b) $4.0 million of surplus Idaho energy efficiency rider funds.

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 PCA mechanism and instead results in collecting that portion through base rates.

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 (Oregon ROE) for the year is at least 100 basis points below Idaho Power’s last authorized Oregon ROE. A refund to customers will occur only to the extent that Idaho Power’s actual Oregon ROE for that year is at least 100 basis points above Idaho Power’s last authorized Oregon ROE. Oregon jurisdiction power supply cost changes under the APCU and PCAM during each of 2018, 2017, and 2016 did not have a material impact on the companies' financial statements.

Notable Idaho Regulatory Matters

Idaho Base Rate Changes: Idaho base rates were most recently established in 2012, and adjusted in 2014, 2017, and 2018. 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 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 PCA rate that became effective June 1, 2014. In June 2018, the IPUC issued an order adjusting base rates for the impacts of income tax reform, as discussed below in "Income Tax Reform - Regulatory Treatment."

October 2014 Idaho Earnings Support and Sharing Settlement Stipulation: In October 2014, the IPUC issued an order approving an extension, with modifications, of the terms of a 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 accumulated deferred investment tax credits (ADITC) contemplated by the settlement stipulation has been amortized (October 2014 Idaho Earnings Support and Sharing Settlement Stipulation). The provisions of the October 2014 Idaho Earnings Support and Sharing Settlement Stipulation are described in the table included under "Income Tax Reform - Regulatory Treatment" below.

In 2018, Idaho Power recorded a $5.0 million provision against current revenue for sharing with customers, as its full-year return on year-end equity in the Idaho jurisdiction (Idaho ROE) for 2018 was above 10.0 percent. In both 2016 and 2017, Idaho Power did not record any additional ADITC amortization or any provision for sharing with customers, as its Idaho ROE in both years was between 9.5 percent and 10.0 percent. Accordingly, at December 31, 2018, the full $45 million of additional ADITC remains available for future use under the terms of the October 2014 Idaho Earnings Support and Sharing Settlement Stipulation. The October 2014 Idaho Earning Support and Sharing Settlement Stipulation was modified and indefinitely extended, as described in "Income Tax Reform - Regulatory Treatment" below.

Income Tax Reform - Regulatory Treatment: In December 2017, the Tax Cuts and Jobs Act was signed into law, which, among other things, lowered the corporate federal income tax rate from 35 percent to 21 percent and modified or eliminated certain federal income tax deductions for corporations. In March 2018, Idaho House Bill 463 was signed into law reducing the Idaho state corporate income tax rate from 7.4 percent to 6.925 percent.

In January 2018, the IPUC issued an order requiring utilities within its jurisdiction, including Idaho Power, to file a report with the IPUC, identifying and quantifying the financial impact of the income tax reform changes on the utility, along with proposed tariff schedule changes that would adjust the utility's rates and corresponding revenues to reflect the utility's modified federal tax obligations under the Tax Cuts and Jobs Act. The IPUC order required Idaho Power to estimate the income tax reform changes by comparing actual 2017 federal income tax components with what those federal income tax components would have been if the Tax Cuts and Jobs Act had been effective for the full-year 2017.

In March 2018, Idaho Power made a filing with the IPUC providing the results of its pro forma analysis indicating pro forma annual income tax reform expense reductions, composed of a current income tax expense reduction and a deferred income tax expense reduction. In May 2018, the IPUC issued an order approving a settlement stipulation (May 2018 Idaho Tax Reform Settlement Stipulation) related to income tax reform. Beginning June 1, 2018, the settlement stipulation provides an annual (a) $18.7 million reduction to Idaho customer base rates and (b) $7.4 million amortization of existing regulatory deferrals for specified items or future amortization of other existing or future unspecified regulatory deferrals that would otherwise be a future liability recoverable from Idaho customers. Additionally, a one-time benefit of a $7.8 million rate reduction is being provided to Idaho customers through the Idaho-jurisdiction power cost adjustment (PCA) mechanism for the period from June 1, 2018 through May 31, 2019, for the income tax reform benefits accrued from January 1, 2018 to May 31, 2018, and the income tax reform benefits related to Idaho Power's OATT rate. The amount provided via the PCA mechanism will decrease to $2.7 million on June 1, 2019, for income tax reform benefits related to Idaho Power's OATT rate and will cease on June 1, 2020, to reflect the impact of a full year of reduced OATT third-party transmission revenues.

The May 2018 Idaho Tax Reform Settlement Stipulation also provides for the indefinite extension, with modifications, of the October 2014 Idaho Earnings Support and Sharing Settlement Stipulation beyond its termination date of December 31, 2019.

The table below summarizes and compares the terms of the October 2014 Idaho Earnings Support and Sharing Settlement Stipulation with the terms in the May 2018 Idaho Tax Reform Settlement Stipulation that will be applicable commencing on January 1, 2020.

October 2014 Idaho Earnings Support and Sharing Settlement Stipulation (Effective through December 31, 2019)	**May 2018 Idaho Tax Reform Settlement Stipulation** (Effective beginning January 1, 2020, with no defined end date)
If Idaho Power's actual annual Idaho ROE in any year is less than 9.5 percent, then Idaho Power may record additional ADITC amortization up to $25 million to help achieve a 9.5 percent Idaho ROE for that year, and may record additional ADITC amortization up to a total of $45 million over the 2015 through 2019 period. If the $45 million of ADITC are completely amortized, the revenue sharing provisions below would no longer be applicable.	If Idaho Power's actual annual Idaho ROE in any year is less than 9.4 percent, then Idaho Power may amortize up to $25 million of additional ADITC to help achieve a 9.4 percent Idaho ROE for that year, so long as the cumulative amount of ADITC used does not exceed $45 million (Idaho Power will have available and may continue to use any unused portion of the $45 million of additional ADITC from the October 2014 Idaho Earnings Support and Sharing Settlement Stipulation); however, Idaho Power may seek approval from the IPUC to replenish the total amount of ADITC it is permitted to amortize. If there are no remaining amounts of ADITC authorized to be amortized, the revenue sharing provisions below would not be applicable until ADITC is replenished.
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 PCA, and 25 percent to Idaho Power.	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 80 percent to Idaho Power's Idaho customers as a rate reduction to be effective at the time of the subsequent year's PCA, and 20 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 PCA, 25 percent to Idaho Power's Idaho customers in the form of a reduction to the pension regulatory asset balancing account (to reduce the amount to be collected in the future from Idaho customers), and 25 percent to Idaho Power.	If 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 55 percent to Idaho Power's Idaho customers as a rate reduction to be effective at the time of the subsequent year's PCA, 25 percent to Idaho Power's Idaho customers in the form of a reduction to the pension regulatory asset balancing account (to reduce the amount to be collected in the future from Idaho customers), and 20 percent to Idaho Power.
In the event the IPUC approves a change to Idaho Power's allowed annual Idaho ROE as part of a general rate case proceeding before December 31, 2019, the Idaho ROE thresholds will be adjusted on a prospective basis as follows: (a) the Idaho ROE under which Idaho Power will be permitted to amortize an additional amount of ADITC will be set at 95 percent of the newly authorized Idaho ROE, (b) sharing with customers on an 75 percent basis as a customer rate reduction will begin at the newly authorized Idaho ROE, and (c) sharing with customers on a 75 percent basis but allocated 50 percent to a rate reduction, and 25 percent to a pension expense deferral regulatory asset, will begin at 105 percent of the newly authorized Idaho ROE.	In the event the IPUC approves a change to Idaho Power's allowed annual Idaho ROE as part of a general rate case proceeding effective on or after January 1, 2020, the Idaho ROE thresholds will be adjusted on a prospective basis as follows: (a) the Idaho ROE under which Idaho Power will be permitted to amortize an additional amount of ADITC will be set at 95 percent of the newly authorized Idaho ROE, (b) sharing with customers on an 80 percent basis as a customer rate reduction will begin at the newly authorized Idaho ROE, and (c) sharing with customers on an 80 percent basis but allocated 55 percent to a rate reduction, and 25 percent to a pension expense deferral regulatory asset, will begin at 105 percent of the newly authorized Idaho ROE.

Neither the October 2014 Idaho Earnings Support and Sharing Settlement Stipulation nor the May 2018 Idaho Tax Reform Settlement Stipulation impose a moratorium on Idaho Power filing a general rate case or other form of rate proceeding in Idaho during their respective terms.

Also in May 2018, the Public Utility Commission of Oregon (OPUC) issued an order approving a settlement stipulation that provides for an annual $1.5 million reduction to Oregon customer base rates beginning June 1, 2018, through May 31, 2020, related to income tax reform. Unless earlier resolved in a regulatory proceeding, the settlement stipulation requires Idaho Power to file a deferral request with the OPUC by December 31, 2019, to begin tracking income tax reform benefits beginning January 1, 2020, at which time Idaho Power, the OPUC staff, and other interested parties will discuss the methodology to quantify potential future income tax reform benefits.

Fixed Cost Adjustment: The Idaho jurisdiction fixed cost adjustment (FCA) mechanism, applicable to Idaho residential and small commercial customers, is designed to remove a portion of 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. Under Idaho Power's current rate design, recovery of a portion of fixed costs is included in the variable kilowatt-hour charge, which may result in over-collection or under-collection of fixed costs. To return over-collection to customers or to collect under-collection from customers, the FCA mechanism allows Idaho Power to accrue, or defer, the difference between the authorized fixed-cost recovery amount per customer and the actual fixed costs per customer recovered by Idaho Power during the year. Any annual increase in the FCA recovery is capped at 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)
2017	June 1, 2018-May 31, 2019	$15.6
2016	June 1, 2017-May 31, 2018	$35.0
2015	June 1, 2016-May 31, 2017	$28.1

Hells Canyon Complex Relicensing Costs Settlement Stipulation: In December 2016, Idaho Power filed an application with the IPUC requesting a determination that Idaho Power's expenditures of $220.8 million through year-end 2015 on relicensing of the HCC were prudently incurred, and thus eligible for inclusion in retail rates in a future regulatory proceeding. In December 2017, Idaho Power filed with the IPUC a settlement stipulation signed by Idaho Power, the IPUC staff, and a third-party intervenor, recognizing that a total of $216.5 million in HCC relicensing expenditures and other related costs were reasonably incurred, and therefore should be eligible for inclusion in customer rates at a later date. As a result of filing the settlement stipulation, Idaho Power recorded a $5.0 million pre-tax charge in the fourth quarter of 2017, which included $4.3 million for costs incurred through 2015, as well as $0.7 million related to associated costs incurred in 2016 and 2017. Of the $5.0 million pre-tax charge in 2017, $2.5 million was recorded as other operations and maintenance (O&M) expense and $2.5 million was recorded as a reduction to AFUDC. In April 2018, the IPUC issued an order approving the settlement stipulation as filed with the IPUC and determined the $216.5 million of associated costs to be reasonably and prudently incurred.

Western Energy Imbalance Market Costs: Idaho Power's participation in the energy imbalance market implemented in the western United States (Western EIM) commenced on April 4, 2018. The Western EIM aims to reduce the power supply costs to serve customers through more efficient dispatch within the hour of a larger and more diverse pool of resources, to integrate intermittent power from renewable generation sources more effectively, and to enhance reliability.

In January 2017, in response to Idaho Power's request to match costs with benefits of Western EIM participation, the IPUC issued an order authorizing deferral accounting treatment for costs associated with joining the Western EIM. In November 2017, Idaho Power filed an application with the IPUC requesting authorization to establish an interim method of recovery for costs associated with participation in the Western EIM. Through March 2018, Idaho Power had deferred $1.0 million of incremental other O&M costs. In the second quarter of 2018, Idaho Power amortized those costs in accordance with the provisions of the May 2018 Idaho Tax Reform Settlement Stipulation discussed above. In July 2018, the IPUC issued an order approving a settlement stipulation that provides for recovery of ongoing Western EIM-related costs through Idaho Power's PCA mechanism, beginning April 2018. The recovery mechanism provides for monthly incremental revenue, which includes a return on and return of Western EIM-related capital costs and recovery of ongoing Western EIM operating costs. As of April 1, 2018, Idaho Power ceased deferring incremental Western EIM participation O&M start-up costs, and began recognizing the monthly incremental revenue associated with Western EIM participation. From April through December 2018, Idaho Power recorded $2.2 million as a regulatory asset within the PCA balance per the stipulation in order to match the costs with the benefits of the Western EIM.

Valmy Base Rate Adjustment Settlement Stipulations

In May 2017, the IPUC approved a settlement stipulation allowing accelerated depreciation and cost recovery for Idaho Power’s jointly-owned North Valmy coal-fired power plant (Valmy Plant). The settlement stipulation provides for an increase in Idaho jurisdictional revenues of $13.3 million per year, and (1) levelized collections and associated cost recovery through December 2028, (2) accelerated depreciation on unit 1 through 2019 and unit 2 through 2025, (3) Idaho Power to use prudent and commercially reasonable efforts to end its participation in the operation of unit 1 by the end of 2019 and unit 2 by the end of 2025, and (4) a filing no later than December 31, 2019 that would include actual and planned incremental investments in unit 2, including updated financial analysis regarding the lowest costs options for unit 2. The costs intended to be recovered by the increased jurisdictional revenues include current investments as of May 31, 2017, in both units, forecasted unit 1 investments from 2017 through 2019, and forecasted decommissioning costs for unit 1 and unit 2, offset by forecasted operation and maintenance costs savings. The settlement stipulation also provides for the regulatory accrual or deferral of the difference between actual revenue requirements and levelized collections, and provides for the regulatory accrual or deferral of the difference between actual costs incurred (including accelerated depreciation expense on unit 1 through 2019 and unit 2 through 2025) compared with costs permitted to be recovered during the cost recovery period specified in the settlement stipulation (including depreciation expense through 2028). If actual costs incurred differ from forecasted amounts included in the settlement stipulation, collection or refund of any differences would be subject to regulatory approval.

In June 2017, the OPUC also approved a settlement stipulation allowing for accelerated depreciation of units 1 and 2 through December 31, 2025, cost recovery of incremental Valmy Plant investments through May 31, 2017, and forecasted decommissioning costs. The settlement stipulation provides for an increase in the Oregon jurisdictional revenue requirement of $1.1 million, effective July 1, 2017, with yearly adjustments, if warranted. As part of the May 2018 settlement stipulation associated with income tax reform described above, the OPUC also deemed prudent Idaho Power's decision to pursue the end of its participation in coal-fired operations of unit 1 by the end of 2019 and approved Idaho Power's request to recover annual incremental accelerated depreciation relating to unit 1, beginning June 1, 2018, and ending December 31, 2019, resulting in a $2.5 million annualized revenue requirement.

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. In June 2018, the OPUC also issued an order adjusting base rates for the impacts of income tax reform, as discussed above in "Income Tax Reform - Regulatory Treatment."

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, 2018 to September 30, 2019	$ 31.25
October 1, 2017 to September 30, 2018	$ 34.90
October 1, 2016 to September 30, 2017	$ 25.52
October 1, 2015 to September 30, 2016	$ 23.43

Idaho Power's current OATT rate is based on a net annual transmission revenue requirement of $123.1 million, which represents the OATT formulaic determination of Idaho Power's net cost of providing OATT-based transmission service.

4. REVENUES

On January 1, 2018, IDACORP and Idaho Power adopted ASU 2014-09, *Revenue from Contracts with Customers,* using the modified retrospective method. The adoption did not change the timing or amounts of revenue recognized by IDACORP or Idaho Power and, therefore, the companies recorded no cumulative-effect adjustment. The following table provides a summary of electric utility operating revenues for IDACORP and Idaho Power (in thousands):

	Year Ended December 31,		
	2018	**2017**	**2016**
Electric utility operating revenues:			
Revenue from contracts with customers	$ 1,312,112	$ 1,320,004	$ 1,216,796
Alternative revenue programs and other revenues	54,470	24,889	42,557
Total electric utility operating revenues	$ 1,366,582	$ 1,344,893	$ 1,259,353

Revenues from Contracts with Customers

Revenues from contracts with customers are primarily related to Idaho Power’s regulated tariff-based sales of energy or related services. Generally, tariff-based sales do not involve a written contract, but are classified as revenues from contracts with customers under ASU 2014-09, *Revenue from Contracts with Customers*. Idaho Power assesses revenues on a contract-by-contract basis to determine the nature, amount, timing, and uncertainty, if any, of revenues being recognized. The following table presents revenues from contracts with customers disaggregated by revenue source (in thousands):

	Year Ended December 31,		
	2018	2017	2016
Revenues from contracts with customers:			
Retail revenues:			
Residential (includes $34,625, $17,320 and $29,170, respectively, related to the FCA[1])	$ 530,527	$ 552,333	$ 514,954
Commercial (includes $1,299, $876 and $1,087, respectively, related to the FCA[1])	310,299	319,195	302,650
Industrial	190,130	195,124	182,590
Irrigation	158,001	150,030	156,505
Provision for sharing	(5,025)	—	—
Deferred revenue related to HCC relicensing AFUDC[2]	(8,780)	(10,706)	(10,706)
Total retail revenues	1,175,152	1,205,976	1,145,993
Less: FCA mechanism revenues[1]	(35,924)	(18,196)	(30,257)
Wholesale energy sales	52,845	24,790	11,900
Transmission wheeling revenues	59,094	43,970	32,496
Energy efficiency program revenues	35,703	39,241	33,754
Other revenues from contracts with customers	25,242	24,223	22,910
Total revenues from contracts with customers	$ 1,312,112	$ 1,320,004	$ 1,216,796

(1) The FCA mechanism is an alternative revenue program in the Idaho jurisdiction and does not represent revenue from contracts with customers.

(2) As part of its January 30, 2009, general rate case order, the IPUC is allowing Idaho Power to recover a portion of the AFUDC on construction work in progress related to the HCC relicensing process, even though the relicensing process is not yet complete and the costs have not been moved to electric plant in service. Idaho Power is collecting $8.8 million annually in the Idaho jurisdiction but is deferring revenue recognition of the amounts collected until the license is issued and the accumulated license costs approved for recovery are placed in service. Prior to the May 2018 Idaho Tax Reform Settlement Stipulation described in Note 3 - "Regulatory Matters," Idaho Power was collecting $10.7 million annually.

Retail Revenues: Idaho Power’s retail revenues primarily relate to the sale of electricity to customers based on regulated tariff-based prices. Idaho Power recognizes retail revenues in amounts for which it has the right to invoice the customer in the period when energy is delivered or services are provided to customers. The total energy price generally has a fixed component related to having service available and a usage-based component related to the demand, delivery, and consumption of energy. The revenues recognized reflect the consideration Idaho Power expects to be entitled to in exchange for energy and services. Retail customers are classified as residential, commercial, industrial, or irrigation. Approximately 95 percent of Idaho Power's retail revenue originates from customers located in Idaho, with the remainder originating from customers located in Oregon. Idaho Power’s retail customer rates are based on Idaho Power’s cost of service and are determined through general rate case proceedings, settlement stipulations, and other filings with the IPUC and OPUC. Changes in rates and changes in customer demand are typically the primary causes of fluctuations in retail revenue from period to period. The primary influences on changes in customer demand for electricity are weather, economic conditions (including growth in the number of Idaho Power customers), and energy efficiency. Idaho Power's utility revenues are not earned evenly during the year.

Retail revenues are billed monthly based on meter readings taken throughout the month. Payments for amounts billed are generally due from the customer within 15 days of billing. Idaho Power accrues estimated unbilled revenues for energy or related services delivered to customers but not yet billed at period-end based on actual meter readings at period-end and estimated rates.

Credit losses recorded on receivables arising from Idaho Power’s contracts with customers were $3.6 million, $4.7 million, and $4.2 million for 2018, 2017, and 2016, respectively.

Residential Customers: Idaho Power’s energy sales to residential customers typically peak during the winter heating season and summer cooling season. Extreme temperatures increase sales to residential customers who use electricity for cooling and heating, compared with normal temperatures. Idaho Power's rate structure provides for higher rates during the summer when overall 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 the seasonal fluctuations in revenues and earnings. Economic and demographic conditions can also affect residential customer demand; strong job growth and population growth in Idaho Power’s service area have led to increasing customer growth rates in recent years. Residential demand is also impacted by energy efficiency initiatives. Idaho Power’s FCA mechanism mitigates some of the fluctuations caused by weather and energy efficiency initiatives.

Commercial Customers: Most businesses are included in Idaho Power's commercial customer class, as well as small industrial companies, and public street and highway lighting accounts. Idaho Power’s commercial customers are less influenced by weather conditions than residential customers, although weather does affect commercial customer energy use. Economic conditions, including manufacturing activity levels, and energy efficiency initiatives also affect energy use of commercial customers.

Industrial Customers: Industrial customers consist of large industrial companies, including special contract customers. Energy use of industrial customers is primarily driven by economic conditions, with weather having little impact on this customer class.

Irrigation Customers: Irrigation customers use electricity to operate irrigation pumps, primarily during the agricultural growing season. The amount and timing of precipitation as well as temperature levels can affect the timing and amounts of sales to irrigation customers, with increased precipitation generally resulting in decreased sales.

Provision for Sharing: Idaho Power's sharing mechanism is associated with the October 2014 Idaho Earnings Support and Sharing Settlement Stipulation that provides for the sharing with customers of a portion of Idaho-jurisdiction earnings exceeding a 10.0 percent Idaho ROE. Based on full-year 2018 Idaho ROE, Idaho Power recorded a $5.0 million provision against current revenues for sharing of earnings with customers for 2018. During 2017 and 2016, Idaho Power recorded no sharing of earnings with customers. The October 2014 Idaho Earnings Support and Sharing Settlement Stipulation is described further in Note 3 - "Regulatory Matters."

Wholesale Energy Sales: As a public utility under the Federal Power Act (FPA), Idaho Power has the authority to charge market-based rates for wholesale energy sales under its FERC tariff. Idaho Power’s wholesale electricity sales are primarily to utilities and power marketers and are predominantly short-term and consist of a single performance obligation satisfied as energy is transferred to the counterparty. Idaho Power's wholesale energy sales depend largely on the availability of generation resources in excess of the amount necessary to serve customer loads as well as adequate market power prices at the time when those resources are available. A reduction in either factor may lead to lower wholesale energy sales.

Transmission Wheeling Revenues: As a public utility under the FPA, Idaho Power has the authority to provide cost-based wholesale and retail access transmission services under its OATT. Services under the OATT are offered on a nondiscriminatory basis such that all potential customers have an equal opportunity to access the transmission system. Idaho Power’s transmission revenue is primarily related to third parties reserving capacity on Idaho Power’s transmission system to transmit electricity through Idaho Power’s service area. The reservations are predominantly short-term but may be part of a long-term capacity contract, short-term contract, or on-demand when available. Transmission wheeling revenues consist of a single performance obligation satisfied as capacity on Idaho Power’s transmission system is provided to the third party. Transmission wheeling revenues are affected by changes in Idaho Power’s OATT rate and customer demand. Demand for transmission services can be affected by regional market factors, such as loads and generation of utilities in Idaho Power’s region.

Energy Efficiency Program Revenues: Idaho Power collects most of its energy efficiency program costs through an energy efficiency rider on customer bills. The rider collections are deferred until expenditures are incurred. Energy efficiency program expenditures funded through the rider are reported as an operating expense with an equal amount recorded in revenues, resulting in no net impact on earnings. Energy efficiency program revenues are recognized in the period when the related costs of the energy efficiency program are incurred by Idaho Power. The cumulative variance between expenditures and amounts collected through the rider is recorded as a regulatory asset or liability. A liability balance indicates that Idaho Power has collected more than it has spent, and an asset balance indicates that Idaho Power has spent more than it has collected. At December 31, 2018, Idaho Power's energy efficiency rider balances were a $5.3 million regulatory liability in the Idaho jurisdiction and a $1.4 million regulatory asset in the Oregon jurisdiction.

Alternative Revenue Programs and Other Revenues

While revenues from contracts with customers make up most of Idaho Power’s revenues, the IPUC has authorized the use of the FCA mechanism, which may increase or decrease tariff-based rates billed to customers. The FCA mechanism is described in detail in Note 3 - "Regulatory Matters." The FCA mechanism revenues include only the initial recognition of FCA revenues when the regulator-specified conditions for recognition have been met. Revenue from contracts with customers excludes the portion of the tariff price representing FCA revenues that had been initially recorded in prior periods when regulator-specified conditions were met. When those amounts are included in the price of utility service and billed to customers, such amounts are recorded as recovery of the associated regulatory asset or liability and not as revenues.

The table below presents the FCA mechanism revenues and other revenues (in thousands):

	Year Ended December 31,		
	2018	**2017**	**2016**
Alternative revenue programs and other revenues:			
FCA mechanism revenues	$ 35,924	18,196	$ 30,257
Derivative revenues	18,546	6,693	12,300
Total alternative revenue programs and other revenues	$ 54,470	$ 24,889	$ 42,557

IDACORP's Other Revenues

IDACORP's other revenues are primarily comprised of revenues from IDACORP’s subsidiary, Ida-West. Ida-West operates small hydroelectric generation projects that satisfy the requirements of PURPA.

5. LONG-TERM DEBT

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

	2018	2017
First mortgage bonds:		
4.50% Series due 2020	$ —	$ 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
6.00% 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	250,000
4.05% Series due 2046	120,000	120,000
4.20% Series due 2048	220,000	—
Total first mortgage bonds	1,665,000	1,575,000
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
Unamortized issuance costs and discounts	(20,557)	(19,222)
Total IDACORP and Idaho Power outstanding debt(2)	1,834,788	1,746,123
Current maturities of long-term debt	—	—
Total long-term debt	$ 1,834,788	$ 1,746,123

(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, 2018, to $1.831 billion.

(2) At December 31, 2018 and 2017, the overall effective cost rate of Idaho Power's outstanding debt was 4.83 percent and 4.87 percent, respectively.

At December 31, 2018, the maturities for the aggregate amount of IDACORP and Idaho Power long-term debt outstanding were as follows (in thousands of dollars):

2019	2020	2021	2022	2023	Thereafter
$ —	$ 100,000	$ —	$ 75,000	$ 75,000	$ 1,605,345

Long-Term Debt Issuances, Maturities, and Availability

In March 2018, Idaho Power issued $220 million in principal amount of 4.20% first mortgage bonds, secured medium-term notes, Series K, maturing on March 1, 2048. In April 2018, Idaho Power redeemed, prior to maturity, $130 million in principal amount of 4.50% first mortgage bonds, medium-term notes, Series H, due March 2020. In accordance with the redemption provisions of the notes, the redemption included Idaho Power's payment of a make-whole premium of $4.6 million. Idaho

Power used a portion of the net proceeds of the March 2018 sale of first mortgage bonds, medium-term notes to effect the redemption.

In March 2016, Idaho Power issued $120.0 million in principal amount of 4.05% first mortgage bonds, secured medium-term notes, Series J, maturing on March 1, 2046. In April 2016, Idaho Power redeemed, prior to maturity, $100.0 million in principal amount of 6.15% first mortgage bonds, secured medium-term notes, Series H, due April 2019. In accordance with the redemption provisions of the notes, the redemption included Idaho Power's payment of a make-whole premium of $14.0 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.

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 and May 2016, 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 is effective through May 31, 2019, subject to extensions upon request to the IPUC. The OPUC's and WPSC's orders do not impose a time limitation for issuances, but the OPUC order does impose a number of other conditions, including a requirement that the interest rates for the debt securities or first mortgage bonds fall within either (a) designated spreads over comparable U.S. Treasury rates or (b) a maximum all-in interest rate limit of 7.0 percent.

On September 27, 2016, Idaho Power entered into a selling agency agreement with seven banks 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 K (Series K Notes), under Idaho Power’s Indenture of Mortgage and Deed of Trust, dated as of October 1, 1937, as amended and supplemented (Indenture). At the same time, Idaho Power entered into the Forty-eighth Supplemental Indenture, dated as of September 1, 2016, to the Indenture. The Forty-eighth Supplemental Indenture provides for, among other items, the issuance of up to $500 million in aggregate principal amount of Series K Notes pursuant to the Indenture. As of December 31, 2018, $280 million in principal amount of Series K Notes remained available for issuance under 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.

The Forty-eighth Supplemental Indenture increased the maximum amount of first mortgage bonds issuable by Idaho Power under the Indenture from $2.0 billion to $2.5 billion. Idaho Power may amend the Indenture and increase this amount without consent of the holders of the first mortgage bonds. The amount issuable is also restricted by property, earnings, and other provisions of the Indenture and supplemental indentures to the Indenture. 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.

As of December 31, 2018, Idaho Power could issue under its Indenture approximately $1.9 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 Forty-eighth Supplemental Indenture. As a result, the maximum amount of first mortgage bonds Idaho Power could issue as of December 31, 2018 was limited to approximately $669 million under the Indenture.

6. 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 zero 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. While the credit facilities provide for an original maturity date of November 6, 2020, the credit agreements grant IDACORP and Idaho Power the right to request up to two one-year extensions, subject to certain conditions. On November 7, 2017, IDACORP and Idaho Power executed the second extension agreement with the consent of all the lenders, extending the maturity date under both credit agreements to November 4, 2022. No other terms of the credit facilities, included the amount of permitted borrowing under the credit agreements, were affected by the extensions.

At December 31, 2018, no loans were outstanding under either IDACORP's or Idaho Power's facilities. At December 31, 2018, 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, 2018, and December 31, 2017:

	IDACORP		Idaho Power		Total	
	2018	**2017**	**2018**	**2017**	**2018**	**2017**
Commercial paper balances:						
At the end of year	$ —	$ —	$ —	$ —	$ —	$ —
Average during the year	$ —	$ 588	$ —	$ 839	$ —	$ 1,427
Weighted-average interest rate						
At the end of the year	—%	—%	—%	—%	—%	—%

7. COMMON STOCK

IDACORP Common Stock

The following table summarizes IDACORP common stock transactions during the last three years and shares reserved at December 31, 2018:

	Shares issued			Shares reserved
	2018	2017	2016	December 31, 2018
Balance at beginning of year	50,420,017	50,420,017	50,352,051	
Continuous equity program (inactive)	—	—	—	3,000,000
Dividend reinvestment and stock purchase plan	—	—	—	2,576,723
Employee savings plan	—	—	—	3,567,954
Long-term incentive and compensation plan(1)	—	—	67,966	1,302,869
Balance at end of year	50,420,017	50,420,017	50,420,017	

(1) During 2018 and 2017, IDACORP granted 75,761 and 72,397 restricted stock unit awards, respectively, to employees and 12,950 and 12,050 shares of common stock, respectively, to directors but made no original issuances of shares of common stock pursuant to the IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan.

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, 2018, the leverage ratios for IDACORP and Idaho Power were 44 percent and 46 percent, respectively. Based on these restrictions, IDACORP's and Idaho Power's dividends were limited to $1.4 billion and $1.2 billion, respectively, at December 31, 2018. 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 IDACORP and Idaho Power from any material subsidiary. At December 31, 2018, 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, 2018, Idaho Power's common equity capital was 54 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 FPA prohibits the payment of dividends from "capital accounts." The term "capital account" is undefined in the FPA 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.

8. SHARE-BASED COMPENSATION

IDACORP has one share-based compensation plan — the 2000 Long-Term Incentive and Compensation Plan (LTICP). The LTICP (for officers, key employees, and directors) permits the grant of stock options, restricted stock and restricted stock units (together, Restricted Stock), performance shares and performance-based units (together, Performance-Based Shares), and several other types of share-based awards. At December 31, 2018, the maximum number of shares available under the LTICP was 720,408.

Restricted Stock and Performance-Based Shares Awards

Restricted Stock awards have three-year vesting periods and entitle the recipients to dividends or dividend equivalents, as applicable, and voting rights, except that holders of restricted stock units do not have voting rights until the units are vested and settled in shares. Unvested awards 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, reduced for any forfeitures during the vesting period.

Performance-Based Shares awards have three-year vesting periods and entitle the recipients to voting rights, except that holders of performance-based units do not have voting rights until the units are vested and settled in shares. Unvested awards 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 200 percent of the target award. Dividends or dividend equivalents, as applicable, 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 estimated achievement of performance targets, reduced for any forfeitures during the vesting period. 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-Based Shares award 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/Units	**Weighted-Average Grant Date Fair Value**	**Number of Shares/Units**	**Weighted-Average Grant Date Fair Value**
Nonvested shares/units at January 1, 2018	201,078	$ 72.37	199,652	$ 72.39
Shares/units granted	106,992	79.28	106,402	79.29
Shares/units forfeited	(5,179)	85.07	(5,179)	85.07
Shares/units vested	(96,856)	60.30	(96,016)	60.31
Nonvested shares/units at December 31, 2018	206,035	$ 81.31	204,859	$ 81.31

The total fair value of shares vested was $8.3 million in 2018, $7.5 million in 2017, and $8.3 million in 2016. At December 31, 2018, IDACORP had $8.0 million of total unrecognized compensation cost related to nonvested share-based compensation. Idaho Power's share of this amount was $7.9 million. These costs are expected to be recognized over a weighted-average period of 1.7 years. IDACORP uses original issue and/or treasury shares for these awards.

In 2018, a total of 12,950 shares were awarded to directors at a grant date fair value of $81.05 per share. Directors elected to defer receipt of 3,237 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 the LTICP, 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		
	2018	**2017**	**2016**	**2018**	**2017**	**2016**
Compensation cost	$ 9,362	$ 7,384	$ 5,561	$ 9,276	$ 7,304	$ 5,494
Income tax benefit[(1)]	2,410	2,887	2,174	2,388	2,856	2,148

(1) Due to the Tax Cuts and Jobs Act, the effective income tax rate was reduced in 2018 for both IDACORP and Idaho Power, which is described in Note 2 - "Income Taxes."

No equity compensation costs have been capitalized. These costs are primarily reported within "Other operations and maintenance" expense on the consolidated statements of income.

9. EARNINGS PER SHARE

The following table presents the computation of IDACORP's basic and diluted earnings per share for the years ended December 31, 2018, 2017, and 2016 (in thousands, except for per share amounts):

	Year Ended December 31,		
	2018	**2017**	**2016**
Numerator:			
Net income attributable to IDACORP, Inc.	$ 226,801	$ 212,419	$ 198,288
Denominator:			
Weighted-average common shares outstanding - basic	50,432	50,361	50,298
Effect of dilutive securities	78	63	75
Weighted-average common shares outstanding - diluted	50,510	50,424	50,373
Basic earnings per share	$ 4.50	$ 4.22	$ 3.94
Diluted earnings per share	$ 4.49	$ 4.21	$ 3.94

10. COMMITMENTS

Purchase Obligations

At December 31, 2018, Idaho Power had the following long-term commitments relating to purchases of energy, capacity, transmission rights, and fuel (in thousands of dollars):

	2019	2020	2021	2022	2023	Thereafter
Cogeneration and power production	$ 238,748	$ 242,206	$ 248,258	$ 251,216	$ 256,403	$2,805,159
Fuel	43,163	29,121	28,010	8,389	8,379	84,182

As of December 31, 2018, Idaho Power had 1,119 MW nameplate capacity of PURPA-related projects on-line, with an additional 29 MW nameplate capacity of projects projected to be on-line in 2019. 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 $190 million in 2018, $170 million in 2017, and $154 million in 2016.

Idaho Power also has the following long-term commitments (in thousands of dollars):

	2019	2020	2021	2022	2023	Thereafter
Joint-operating agreement payments(1)	$ 2,902	$ 2,902	$ 2,902	$ 2,902	$ 2,902	$ 14,512
Easements and other payments	240	1,321	1,321	1,331	1,328	16,831
Maintenance and service agreements(1)	34,089	15,694	10,739	11,713	4,140	54,927
FERC and other industry-related fees(1)	14,277	12,714	12,714	12,714	12,714	63,568

(1) Approximately $29 million, $20 million, and $71 million of the obligations included in joint-operating agreement payments, maintenance and service agreements, and FERC and other industry-related fees, respectively, have contracts that do not specify terms related to expiration. As these contracts are presumed to continue indefinitely, ten years of information, estimated based on current contract terms, has been included in the table for presentation purposes.

IDACORP's expense for operating leases was not material for the years ended 2018, 2017, and 2016.

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 (WDEQ), was $58.4 million at December 31, 2018, representing IERCo's one-third share of BCC's total reclamation obligation of $175.2 million. BCC has a reclamation trust fund set aside specifically for the purpose of paying these reclamation costs. At December 31, 2018, the value of the reclamation trust fund was $101.9 million. During 2018, the reclamation trust fund made distributions of $6.7 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, and does, add a per-ton surcharge to coal sales, all of which are made to the Jim Bridger plant. 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, 2018, 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.

11. 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, some of which 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. 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, although there is no assurance that such recovery would be granted.

IDACORP and Idaho Power are parties to legal claims and legal and regulatory actions and proceedings in the ordinary course of business and, as noted above, record an accrual for associated loss contingencies when they are probable and reasonably estimable. In connection with its utility operations, Idaho Power is subject to claims by individuals, entities, and governmental agencies for damages for alleged personal injury, property damage, and economic losses, relating to the company's provision of electric service and the operation of its generation, transmission, and distribution facilities. Some of those claims relate to electrical contacts, service quality, property damage, and wildfires. In recent years, utilities in the western United States have been subject to significant liability for personal injury, loss of life, property damage, trespass, and economic losses, and in some cases, punitive damages and criminal charges, associated with wildfires that originated from utility property, most commonly transmission and distribution lines. In recent years, Idaho Power has regularly received claims by both governmental agencies and private landowners for damages for fires allegedly originating from Idaho Power's transmission and distribution system. As of the date of this report, the companies believe that resolution of existing claims will not have a material adverse effect on their respective consolidated financial statements. Idaho Power is also actively monitoring various pending environmental regulations and executive orders related to environmental matters 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.

12. 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 two nonqualified defined benefit pension plans for certain senior management employees called the Security Plan for Senior Management Employees I and Security Plan for Senior Management Employees II (together, 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 2018, 2017, and 2016, 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	
	2018	2017	2018	2017
Change in projected benefit obligation:				
Benefit obligation at January 1	$ 999,344	$ 895,060	$ 110,303	$ 99,570
Service cost	37,836	33,742	(316)	759
Interest cost	38,833	38,957	4,248	4,315
Actuarial (gain) loss	(84,758)	67,758	(7,050)	10,635
Benefits paid	(39,398)	(36,173)	(4,867)	(4,976)
Projected benefit obligation at December 31	951,857	999,344	102,318	110,303
Change in plan assets:				
Fair value at January 1	697,683	607,568	—	—
Actual (loss) return on plan assets	(47,681)	86,288	—	—
Employer contributions	40,000	40,000	—	—
Benefits paid	(39,398)	(36,173)	—	—
Fair value at December 31	650,604	697,683	—	—
Funded status at end of year	$ (301,253)	$ (301,661)	$ (102,318)	$ (110,303)
Amounts recognized in the statement of financial position consist of:				
Other current liabilities	$ —	$ —	$ (5,158)	$ (5,010)
Noncurrent liabilities	(301,253)	(301,661)	(97,160)	(105,293)
Net amount recognized	$ (301,253)	$ (301,661)	$ (102,318)	$ (110,303)
Amounts recognized in accumulated other comprehensive income consist of:				
Net loss	$ 278,720	$ 277,052	$ 30,496	$ 41,333
Prior service cost	62	68	399	498
Subtotal	278,782	277,120	30,895	41,831
Less amount recorded as regulatory asset	(278,782)	(277,120)	—	—
Net amount recognized in accumulated other comprehensive income	$ —	$ —	$ 30,895	$ 41,831
Accumulated benefit obligation	$ 814,549	$ 850,763	$ 94,630	$ 100,222

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 $92.5 million and $85.7 million at December 31, 2018 and 2017, 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		
	2018	**2017**	**2016**	**2018**	**2017**	**2016**
Service cost	$ 37,836	$ 33,742	$ 32,019	$ (316)	$ 759	$ 1,228
Interest cost	38,833	38,957	37,813	4,248	4,315	4,275
Expected return on assets	(52,302)	(45,138)	(42,081)	—	—	—
Amortization of net loss	13,558	13,190	13,331	3,788	2,963	3,532
Amortization of prior service cost	6	28	59	98	127	168
Net periodic pension cost	37,931	40,779	41,141	7,818	8,164	9,203
Regulatory deferral of net periodic benefit cost(1)	(36,153)	(38,699)	(39,335)	—	—	—
Previously deferred pension cost recognized(1)	17,154	17,154	17,154	—	—	—
Net periodic benefit cost recognized for financial reporting(1)(2)	$ 18,932	$ 19,234	$ 18,960	$ 7,818	$ 8,164	$ 9,203

(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, the Idaho portion of net periodic benefit cost is recorded as a regulatory asset and is recognized in the income statement as those costs are recovered through rates.

(2) Of total net periodic benefit cost recognized for financial reporting $15.2 million, $16.2 million, and $16.4 million, respectively, was recognized in "Other operations and maintenance" and $11.6 million, $11.2 million, and $11.8 million, respectively, was recognized in "Other expense, net" on the consolidated statements of income of the companies for the twelve months ended December 31, 2018, 2017, and 2016.

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

	Pension Plan			SMSP		
	2018	**2017**	**2016**	**2018**	**2017**	**2016**
Actuarial (loss) gain during the year	$ (15,226)	$ (26,608)	$ (23,753)	$ 7,049	$ (10,635)	$ (2,933)
Plan amendment service cost	—	—	(81)	—	—	(120)
Reclassification adjustments for:						
Amortization of net loss	13,558	13,190	13,331	3,788	2,963	3,532
Amortization of prior service cost	6	28	59	98	127	168
Adjustment for deferred tax effects	428	1,744	4,083	(2,815)	1,555	(253)
Adjustment due to the effects of regulation	1,234	11,646	6,361	—	—	—
Other comprehensive income recognized related to pension benefit plans	$ —	$ —	$ —	$ 8,120	$ (5,990)	$ 394

In 2019, IDACORP and Idaho Power expect to recognize as components of net periodic benefit cost $16.5 million from amortizing amounts recorded in accumulated other comprehensive income (or as a regulatory asset for the pension plan) as of December 31, 2018, relating to the pension plan and SMSP. This amount consists of $13.9 million of amortization of net loss for the pension plan and $2.5 million of amortization of net loss and $0.1 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):

	2019	**2020**	**2021**	**2022**	**2023**	**2023-2028**
Pension Plan	$ 38,177	$ 40,287	$ 42,403	$ 44,489	$ 46,671	$ 264,707
SMSP	5,266	5,716	5,901	6,071	6,431	31,867

As of December 31, 2018, IDACORP's and Idaho Power's minimum required contributions to the pension plan are estimated to be zero in 2019. Depending on market conditions and cash flow considerations in 2019, Idaho Power could contribute up to

$40 million to the pension plan during 2019 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):

	2018	2017
Change in accumulated benefit obligation:		
Benefit obligation at January 1	$ 70,051	$ 63,876
Service cost	1,051	973
Interest cost	2,643	2,783
Actuarial (gain) loss	(2,688)	5,769
Benefits paid[(1)]	(4,604)	(3,562)
Plan amendments	—	212
Benefit obligation at December 31	66,453	70,051
Change in plan assets:		
Fair value of plan assets at January 1	38,294	34,999
Actual (loss) return on plan assets	(1,330)	5,112
Employer contributions[(1)]	1,031	1,745
Benefits paid[(1)]	(4,604)	(3,562)
Fair value of plan assets at December 31	33,391	38,294
Funded status at end of year (included in noncurrent liabilities)	$ (33,062)	$ (31,757)

(1) Contributions and benefits paid are each net of $3.1 million and $3.4 million of plan participant contributions for 2018 and 2017, respectively.

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

	2018	2017
Net (loss) gain	$ (330)	$ 2,777
Prior service cost	222	269
Subtotal	(108)	3,046
Less amount recognized in regulatory assets	108	(3,046)
Net amount recognized in accumulated other comprehensive income	$ —	$ —

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

	2018	2017	2016
Service cost	$ 1,051	$ 973	$ 1,116
Interest cost	2,643	2,783	2,766
Expected return on plan assets	(2,467)	(2,307)	(2,474)
Immediate recognition of loss from temporary deviation[(1)]	4,216	—	—
Amortization of prior service cost	47	47	26
Net periodic postretirement benefit cost	$ 5,490	$ 1,496	$ 1,434

(1) In 2018, a loss associated with a temporary deviation from the cost-sharing provisions of the substantive plan was recognized in "Other expense, net" on the consolidated statements of income of the companies.

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

	2018	2017	2016
Actuarial loss during the year	$ (1,109)	$ (2,964)	$ (1,600)
Prior service cost arising during the year	—	(212)	—
Reclassification adjustments for:			
Immediate recognition of loss from temporary deviation[(1)]	4,216	—	—
Reclassification adjustments for amortization of prior service cost	47	47	26
Adjustment for deferred tax effects	270	807	615
Adjustment due to the effects of regulation	(3,424)	2,322	959
Other comprehensive income related to postretirement benefit plans	$ —	$ —	$ —

(1) In 2018, a loss associated with a temporary deviation from the cost-sharing provisions of the substantive plan was recognized in "Other expense, net" on the consolidated statements of income of the companies.

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

	2019	2020	2021	2022	2023	2023-2027
Expected benefit payments	$ 5,438	$ 5,051	$ 4,894	$ 4,732	$ 4,549	$ 20,080

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	
	2018	2017	2018	2017	2018	2017
Discount rate	4.55%	3.95%	4.60%	3.95%	4.60%	3.95%
Rate of compensation increase[(1)]	4.25%	4.17%	4.75%	4.75%	—	—
Medical trend rate	—	—	—	—	6.3%	6.8%
Dental trend rate	—	—	—	—	4.0%	4.0%
Measurement date	12/31/2018	12/31/2017	12/31/2018	12/31/2017	12/31/2018	12/31/2017

(1) The 2018 rate of compensation increase assumption for the pension plan includes an inflation component of 2.50% plus a 1.75% 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		
	2018	2017	2016	2018	2017	2016	2018	2017	2016
Discount rate	3.95%	4.45%	4.60%	3.95%	4.45%	4.60%	3.95%	4.45%	4.60%
Expected long-term rate of return on assets	7.50%	7.50%	7.50%	—	—	—	6.75%	6.75%	7.25%
Rate of compensation increase	4.25%	4.17%	4.11%	4.75%	4.75%	4.50%	—	—%	—%
Medical trend rate	—	—	—	—	—	—	6.3%	6.8%	8.3%
Dental trend rate	—	—	—	—	—	—	4.0%	4.0%	5.0%

The assumed health care cost trend rate used to measure the expected cost of health benefits covered by the postretirement plan was 6.3 percent in 2018 and is assumed to decrease to 5.7 percent in 2019, 5.1 percent in 2020, 5.1 percent in 2021 and to gradually decrease to 4.1 percent by 2076. The assumed dental cost trend rate used to measure the expected cost of dental benefits covered by the plan was 4.0 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, 2018 (in thousands of dollars):

	One-Percentage-Point	
	Increase	**Decrease**
Effect on total of cost components	$ 339	$ (247)
Effect on accumulated postretirement benefit obligation	3,222	(2,483)

Plan Assets

Pension Asset Allocation Policy: The target allocation and actual allocations at December 31, 2018, for the pension asset portfolio by asset class is set forth below:

Asset Class	**Target Allocation**	**Actual Allocation December 31, 2018**
Debt securities	24%	26%
Equity securities	56%	56%
Real estate	7%	6%
Other plan assets	13%	12%
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 plan participants.

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 approximately 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, 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 17 - "Fair Value Measurements." The following table presents the fair value of the plans' investments by asset category (in thousands of dollars).

	Level 1	Level 2	Level 3	Total
Assets at December 31, 2018				
Cash and cash equivalents	$ 9,717	$ —	$ —	$ 9,717
Short-term bonds	20,644	—	—	20,644
Intermediate bonds	20,595	87,646	—	108,241
Long-term bonds	—	40,857	—	40,857
Equity Securities: Large-Cap	71,176	—	—	71,176
Equity Securities: Mid-Cap	71,419	—	—	71,419
Equity Securities: Small-Cap	53,401	—	—	53,401
Equity Securities: Micro-Cap	30,387	—	—	30,387
Equity Securities: International	7,104	—	—	7,104
Equity Securities: Emerging Markets	6,519	—	—	6,519
Plan assets measured at NAV (not subject to hierarchy disclosure)				
Equity Securities: Global and International				95,653
Equity Securities: Emerging Markets				29,757
Real estate				39,846
Private market investments				35,041
Commodities fund				30,842
Total	$ 290,962	$ 128,503	$ —	$ 650,604
Postretirement plan assets(1)	$ 758	$ 32,633	$ —	$ 33,391

	Level 1	Level 2	Level 3	Total
Assets at December 31, 2017				
Cash and cash equivalents	$ 20,852	$ —	$ —	$ 20,852
Short-term bonds	20,475	—	—	20,475
Intermediate bonds	20,699	82,923	—	103,622
Long-term bonds	—	40,707	—	40,707
Equity Securities: Large-Cap	95,179	—	—	95,179
Equity Securities: Mid-Cap	81,127	—	—	81,127
Equity Securities: Small-Cap	62,502	—	—	62,502
Equity Securities: Micro-Cap	32,753	—	—	32,753
Equity Securities: International	6,774	—	—	6,774
Equity Securities: Emerging Markets	8,785	—	—	8,785
Plan assets measured at NAV (not subject to hierarchy disclosure)				
Equity Securities: International				83,589
Equity Securities: Emerging Markets				36,255
Real estate				38,435
Private market investments				31,618
Commodities fund				35,010
Total	$ 349,146	$ 123,630	$ —	$ 697,683
Postretirement plan assets(1)	$ 567	$ 37,727	$ —	$ 38,294

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

For the years ended December 31, 2018 and 2017, there were no material transfers into or out of Levels 1, 2, or 3.

Fair Value Measurement of Level 2 Plan assets and Plan assets measured at NAV:

Level 2 Bonds: These investments represent U.S. government, agency bonds, and corporate bonds. The U.S. government and agency bonds, as well as the corporate bonds, are not traded on an exchange and are valued utilizing market prices for similar assets or liabilities in active markets.

Level 2 Postretirement Asset: This asset represents an investment in a life insurance contract and is 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.

Commingled Funds: These funds, made up of the global, international, emerging markets equity securities, and commodities fund measured at NAV, are not publicly traded, and therefore no publicly quoted market price is readily available. The values of the commingled funds are presented at estimated fair value, which is determined based on the unit value of the fund. The values of these investments are calculated by the custodian for the fund company on a monthly or more frequent basis, and are based on market prices of the assets held by each of the commingled funds divided by the number of fund shares outstanding for the respective fund. The investments in commingled funds have redemption limitations that permit monthly redemption following notice requirements of 5 to 7 days.

Real Estate: Real estate holdings represent investments in 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 companies, 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 real estate funds also furnish annual audited financial statements that are also used to further validate the information provided. Redemptions are generally available on a quarterly basis, with 10 to 35 days written notice, depending on the individual fund. If the fund has sufficient liquidity, the redemption will be processed at the fund NAV or the fund’s estimate of fair value at the end of the quarter. If the fund does not have sufficient liquidity to honor the full redemption, the remainder will be set for redemption the following quarter on a pro-rata basis with other redemption requests. This same process will repeat until the redemption request has been completed. To protect other fund holders, real estate funds have no duty to liquidate or encumber funds to meet redemption requests.

Private Market Investments: Private market investments represent two categories: fund of hedge funds and venture capital funds. These funds are valued by the fund companies based on the estimated fair values of the underlying fund holdings divided by the fund shares outstanding or multiplied by the ownership percentages of the holder. 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. Redemptions are available on a quarterly basis with 70 days written notice. Redemptions will be processed at the quarterly NAV or fair value within 60 days following quarter end. In the event of a full redemption, a reserve amount of 5% to 10% of the redemption amount may be held in reserve until the audited financial statements of the fund are published. This allows the fund to adjust the redemption so that other fund holders are not adversely impacted. Venture capital fund investments are valued by the fund companies 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. These funds are formed for a stated life of 10 to 15 years. The general partner can extend the fund life for 2 or 3 one-year periods. The fund can be further extended with the approval of the limited partners. There are generally no redemption rights associated with these funds. The limited partner must hold the fund for the life of the fund or find a third-party buyer.

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 $7.7 million, $7.4 million, and $7.5 million in 2018, 2017, and 2016, respectively.

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 benefits included in other deferred credits on both IDACORP’s and Idaho Power’s consolidated balance sheets at December 31, 2018, and 2017, were approximately $2 million.

13. 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 ended December 31, 2018 and 2017 (in thousands of dollars):

	2018		2017	
	Balance	Avg Rate	Balance	Avg Rate
Production	$ 2,654,201	3.10%	$ 2,598,940	3.07%
Transmission	1,201,092	1.89%	1,163,240	1.94%
Distribution	1,792,284	2.24%	1,710,126	2.44%
General and Other	456,279	6.40%	433,856	6.01%
Total in service	6,103,856	2.84%	5,906,162	2.87%
Accumulated provision for depreciation	(2,210,781)		(2,098,274)	
In service - net	$ 3,893,075		$ 3,807,888	

At December 31, 2018, Idaho Power's construction work in progress balance of $480.3 million included relicensing costs of $297.0 million for the HCC, Idaho Power's largest hydroelectric complex. In 2018, 2017, and 2016, the IPUC authorized Idaho Power to include in its Idaho jurisdiction rates $6.5 million annually ($8.8 million when grossed-up for the effect of income taxes in 2018 and $10.7 million when grossed-up for the effect of income taxes in 2017 and 2016 prior to income tax reform described in Note 2 - "Income Taxes") of AFUDC relating to the HCC relicensing project. Collecting these amounts will reduce the amount collected in the future once the HCC relicensing costs are approved for recovery in base rates. At December 31, 2018, Idaho Power's regulatory liability for collection of AFUDC relating to the HCC was $135.1 million.

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, 2018 (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	$ 733,451	$ 5,141	$ 334,731	33	771
Boardman	Boardman, OR	82,459	4	74,748	10	64
Valmy units 1 and 2	Winnemucca, NV	410,947	248	279,643	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 $81.8 million in 2018, $86.4 million in 2017, and $92.9 million in 2016.

Idaho Power has contracts to purchase the energy from four PURPA qualifying facilities that are 50 percent owned by Ida-West. Idaho Power’s power purchases from these facilities were $9.7 million in 2018, $9.8 million in 2017, and $7.8 million in 2016.

IDACORP's consolidated VIE, Marysville, owns a hydroelectric plant with a net book value of $15.2 million and $15.7 million at December 31, 2018 and 2017, respectively.

14. 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. Accretion, depreciation, and gains or losses related to the Boardman generating facility are 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.

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.

Idaho Power also collect removal costs in rates for certain assets that do not have associated AROs. Idaho Power is required to classify these removal costs as regulatory liabilities, see Note 3 - "Regulatory Matters" for the removal costs recorded as regulatory liabilities on IDACORP's and Idaho Power's consolidated balance sheets as of December 31, 2018 and 2017.

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

	2018	2017
Balance at beginning of year	$ 26,415	$ 26,257
Accretion expense	1,055	1,015
Revisions in estimated cash flows	(751)	(791)
Liability incurred	129	—
Liability settled	(56)	(66)
Balance at end of year	$ 26,792	$ 26,415

15. INVESTMENTS

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

	2018	2017
Idaho Power investments:		
Bridger Coal Company (equity method investment)	$ 49,878	$ 68,566
Exchange traded short-term bond funds and cash equivalents	36,471	30,249
Executive deferred compensation plan investments	17	17
Total Idaho Power investments	86,366	98,832
Investments in affordable housing (IDACORP Financial Services)	3,446	5,521
Ida-West joint ventures (equity method investments)	11,366	11,345
Total IDACORP investments	$ 101,178	$ 115,698

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 of unconsolidated equity-method investments (in thousands of dollars):

	2018	2017	2016
Bridger Coal Company (Idaho Power)	$ 10,712	$ 9,267	$ 10,855
Ida-West joint ventures	1,737	2,107	2,016
Total	$ 12,449	$ 11,374	$ 12,871

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, 2018 and December 31, 2017. The following table summarizes sales of available-for-sale securities (in thousands of dollars):

	2018	2017	2016
Proceeds from sales	$ 5,007	$ 4,989	$ 15,693
Gross realized gains from sales	—	—	54

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. IDACORP accounts for its equity-method investments in qualified affordable housing projects using the proportional amortization method and recognizes the net investment performance in the consolidated statements of income as a component of income tax expense.

16. 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, 2018, 2017, and 2016 (in thousands of dollars):

	Location of Realized Gain/(Loss) on Derivatives Recognized in Income	Gain/(Loss) on Derivatives Recognized in Income[1] 2018	2017	2016
Financial swaps	Operating revenues	$ 1,316	$ 902	$ 1,405
Financial swaps	Purchased power	7,828	166	586
Financial swaps	Fuel expense	22,563	701	(1,947)
Financial swaps	Other operations and maintenance	118	(84)	(161)
Forward contracts	Operating revenues	41	55	(54)
Forward contracts	Purchased power	(54)	(69)	86
Forward contracts	Fuel expense	(186)	4	139

(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 revenues from contracts with customers 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 17 - "Fair Value Measurements" 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, 2018 and 2017 (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, 2018							
Current:							
Financial swaps	Other current assets	$ 4,639	$ (984) [1]	$ 3,655	$ 938	$ (938)	$ —
Financial swaps	Other current liabilities	—	—	—	806	—	806
Forward contracts	Other current liabilities	—	—	—	104	—	104
Long-term:							
Financial swaps	Other liabilities	—	—	—	64	—	64
Total		$ 4,639	$ (984)	$ 3,655	$ 1,912	$ (938)	$ 974
December 31, 2017							
Current:							
Financial swaps	Other current assets	$ 18	$ —	$ 18	$ —	$ —	$ —
Financial swaps	Other current liabilities	553	(553)	—	1,971	(748) [2]	1,223
Forward contracts	Other current liabilities	—	—	—	2	—	2
Long-term:							
Financial swaps	Other assets	4	—	4	—	—	—
Total		$ 575	$ (553)	$ 22	$ 1,973	$ (748)	$ 1,225

(1) Current asset derivative amounts offset include $45 thousand of collateral payable for the period ending December 31, 2018.
(2) Current liability derivative amounts offset include $196 thousand of collateral receivable for the period ending December 31, 2017.

The table below presents the volumes of derivative commodity forward contracts and swaps outstanding at December 31, 2018 and 2017 (in thousands of units):

		December 31,	
Commodity	Units	2018	2017
Electricity purchases	MWh	52	312
Electricity sales	MWh	39	224
Natural gas purchases	MMBtu	7,514	7,028
Natural gas sales	MMBtu	446	140

Credit Risk

At December 31, 2018, 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 WSPP, Inc. 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, 2018, was $1.9 million. Idaho Power posted no cash collateral related to this amount. If the credit-risk-related contingent features underlying these agreements were triggered on December 31, 2018, Idaho Power would have been required to pay or post collateral to its counterparties up to an additional $7.8 million to cover open liability positions as well as completed transactions that have not yet been paid.

17. 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 have 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, 2018 and 2017.

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, 2018 and 2017 (in thousands of dollars):

	December 31, 2018				December 31, 2017			
	Level 1	**Level 2**	**Level 3**	**Total**	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets:								
Money market funds and commercial paper								
IDACORP[1]	$ 97,833	$ —	$ —	$ 97,833	$ 28,038	$ —	$ —	$ 28,038
Idaho Power	79,228	—	—	79,228	10,260	—	—	10,260
Derivatives	3,655	—	—	3,655	22	—	—	22
Equity securities	36,488	—	—	36,488	30,266	—	—	30,266
Liabilities:								
Derivatives	$ 870	$ 104	$ —	$ 974	$ 1,223	$ 2	$ —	$ 1,225

(1) Holding company only. Does not include amounts held by Idaho Power.

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 with quoted prices in an active market. Natural gas and diesel derivatives are valued using New York Mercantile Exchange and Intercontinental Exchange pricing, adjusted for location basis, which are also quoted under NYMEX and ICE pricing. Equity securities consist of employee-directed investments related to an executive deferred compensation plan and actively traded money market and exchange traded funds related to the SMSP. The investments are measured using quoted prices in active markets 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, 2018 and 2017, using available market information and appropriate valuation methodologies (in thousands).

	December 31, 2018		December 31, 2017	
	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]	1,834,788	1,942,773	1,746,123	1,915,459
Idaho Power				
Liabilities:				
Long-term debt[1]	$ 1,834,788	$ 1,942,773	$ 1,746,123	$ 1,915,459

(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 17 - "Fair Value Measurements."

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.

18. 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 one-third 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, 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):

	Utility Operations	All Other	Eliminations	Consolidated Total
2018				
Revenues	$ 1,366,582	$ 4,170	$ —	$ 1,370,752
Operating income	295,256	1,666	—	296,922
Other income, net	11,646	(1)	—	11,645
Interest income	8,923	1,573	(655)	9,841
Equity-method income	10,712	1,737	—	12,449
Interest expense	85,891	712	(655)	85,948
Income before income taxes	240,646	4,263	—	244,909
Income tax expense (benefit)	18,312	(926)	—	17,386
Income attributable to IDACORP, Inc.	222,334	4,467	—	226,801
Total assets	6,254,400	163,540	(35,186)	6,382,754
Expenditures for long-lived assets	277,823	30	—	277,853

	Utility Operations	All Other	Eliminations	Consolidated Total
2017				
Revenues	$ 1,344,893	$ 4,593	$ —	$ 1,349,486
Operating income	313,602	1,943	—	315,545
Other income, net	12,356	191	—	12,547
Interest income	6,044	295	(211)	6,128
Equity-method income	9,267	2,107	—	11,374
Interest expense	83,660	297	(211)	83,746
Income before income taxes	257,609	4,239	—	261,848
Income tax expense (benefit)	51,262	(2,602)	—	48,660
Income attributable to IDACORP, Inc.	206,347	6,072	—	212,419
Total assets	5,995,435	143,696	(93,726)	6,045,405
Expenditures for long-lived assets	285,471	17	—	285,488
2016				
Revenues	$ 1,259,353	$ 2,667	$ —	$ 1,262,020
Operating income	277,297	6,285	—	283,582
Other income, net	15,852	6	—	15,858
Interest income	4,235	127	(121)	4,241
Equity-method income	10,855	2,016	—	12,871
Interest expense	81,812	344	(121)	82,035
Income before income taxes	226,427	8,090	—	234,517
Income tax expense (benefit)	37,185	(756)	—	36,429
Income attributable to IDACORP, Inc.	189,242	9,046	—	198,288
Total assets	6,236,744	73,137	(19,984)	6,289,897
Expenditures for long-lived assets	296,948	2	—	296,950

19. OTHER INCOME AND EXPENSE

The following table presents the components of IDACORP's other expense, net and Idaho Power's other expense, net (in thousands of dollars):

IDACORP	**2018**	**2017**	**2016**
Interest and dividend income, net	$ 5,605	$ 3,872	$ 4,466
Carrying charges on regulatory assets	4,075	2,310	2,082
Pension and postretirement non-service costs(1)	(15,781)	(11,194)	(11,806)
Income from life insurance investments	2,779	2,090	2,588
Other income	455	813	738
Total other expense, net	$ (2,867)	$ (2,109)	$ (1,932)

Idaho Power			
Interest and dividend income, net	$ 4,688	$ 3,787	$ 4,460
Carrying charges on regulatory assets	4,075	2,310	2,082
Pension and postretirement non-service costs(1)	(15,781)	(11,194)	(11,806)
Income from life insurance investments	2,779	2,090	2,588
Other expense	(1,612)	(1,749)	(1,871)
Total other expense, net	$ (5,851)	$ (4,756)	$ (4,547)

(1) The 2018 pension and postretirement non-service costs includes $4.2 million of expense for a temporary deviation from the cost-sharing provisions of the substantive postretirement plan as described in Note 12 - "Benefit Plans."

20. CHANGES IN ACCUMULATED OTHER COMPREHENSIVE INCOME

Comprehensive income includes net income 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, 2018, 2017, and 2016 (in thousands of dollars). Items in parentheses indicate reductions to AOCI.

	Year Ended December 31,		
	2018	**2017**	**2016**
Defined benefit pension items			
Balance at beginning of period	$ (30,964)	$ (20,882)	$ (21,276)
Other comprehensive income before reclassifications	5,234	(7,872)	(1,859)
Amounts reclassified out of AOCI to net income	2,886	1,882	2,253
Net current-period other comprehensive income	8,120	(5,990)	394
Cumulative effect of change in accounting principle(1)	—	(4,092)	—
Balance at end of period	$ (22,844)	$ (30,964)	$ (20,882)

(1) The cumulative effect of change in accounting principle relates to the 2017 adoption of ASU 2018-02, *Income Statement—Reporting Comprehensive Income (Topic 220).*

The table below presents the effects on net income of amounts reclassified out of components of AOCI and the income statement location of those amounts reclassified during the years ended December 31, 2018, 2017, and 2016 (in thousands of dollars). Items in parentheses indicate increases to net income.

	Amount Reclassified from AOCI		
	Year Ended December 31,		
	2018	2017	2016
Amortization of defined benefit pension items[1]			
Prior service cost	$ 98	$ 127	$ 168
Net loss	3,788	2,963	3,532
Total before tax	3,886	3,090	3,700
Tax benefit[2]	(1,000)	(1,208)	(1,447)
Net of tax	2,886	1,882	2,253
Total reclassification for the period	$ 2,886	$ 1,882	$ 2,253

(1) 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.

(2) The tax benefit is included in income tax expense in the consolidated income statements of both IDACORP and Idaho Power.

21. 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 $0.7 million in both 2018 and 2017 and $0.8 million in 2016.

At December 31, 2018 and 2017, Idaho Power had a $1.9 million and $57.3 million payable to IDACORP, respectively, which was included in its accounts payable to affiliates balance on its consolidated balance sheets. In 2018, Idaho Power paid IDACORP certain estimated income taxes that had been accrued at December 31, 2017.

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 $9.7 million in 2018, $9.8 million in 2017, and $7.8 million in 2016 for that power.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of IDACORP, Inc.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of IDACORP, Inc. and subsidiaries (the “Company”) as of December 31, 2018 and 2017, the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2018, and the related notes and the schedules listed in the Index at Item 8 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company’s internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 21, 2019, expressed an unqualified opinion on the Company’s internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ *DELOITTE & TOUCHE LLP*

Boise, Idaho
February 21, 2019

We have served as the Company's auditor since 1932.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholder and the Board of Directors of Idaho Power Company

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Idaho Power Company and subsidiary (the "Company") as of December 31, 2018 and 2017, 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, 2018, and the related notes and the schedule listed in the Index at Item 8 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 21, 2019, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ *DELOITTE & TOUCHE LLP*

Boise, Idaho
February 21, 2019

We have served as the Company's auditor since 1932.

SUPPLEMENTAL FINANCIAL INFORMATION, UNAUDITED

QUARTERLY FINANCIAL DATA

The following unaudited information is presented for each quarter of 2018 and 2017 (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.				
2018				
Revenues	$ 310,107	$ 339,952	$ 408,801	$ 311,892
Operating income	50,589	82,835	115,233	48,265
Net income	36,111	62,593	102,591	26,228
Net income attributable to IDACORP, Inc.	36,142	62,288	102,231	26,140
Basic earnings per share	$ 0.72	$ 1.24	$ 2.03	$ 0.52
Diluted earnings per share	$ 0.72	$ 1.23	$ 2.02	$ 0.52
2017				
Revenues	$ 302,544	$ 333,006	$ 408,324	$ 305,612
Operating income(1)	53,627	81,907	123,707	56,304
Net income	33,006	50,096	91,076	39,010
Net income attributable to IDACORP, Inc.	33,102	49,831	90,634	38,852
Basic earnings per share	$ 0.66	$ 0.99	$ 1.80	$ 0.77
Diluted earnings per share	$ 0.66	$ 0.99	$ 1.80	$ 0.77
Idaho Power Company				
2018				
Revenues	$ 309,461	$ 338,699	$ 407,355	$ 311,067
Income from operations	51,120	82,659	114,963	48,581
Net income	35,857	60,637	100,194	25,646
2017				
Revenues	$ 301,964	$ 331,768	$ 406,655	$ 304,506
Income from operations(1)	54,350	81,777	123,293	56,554
Net income	32,482	48,381	88,329	37,155

(1) Operating income in 2017 reflects the 2018 adoption of Accounting Standards Update 2017-07. Retrospective adjustments were made to prior periods to conform with current period presentation. For additional information, refer to Note 1 - "Summary of Significant Accounting Policies" to the consolidated financial statements included in this report.

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, 2018, 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, 2018. 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, 2018, 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, 2018 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, 2018.

February 21, 2019

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholders and the Board of Directors of IDACORP, Inc.

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of IDACORP, Inc. and subsidiaries (the "Company") as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2018 of the Company and our report dated February 21, 2019 expressed an unqualified opinion on those financial statements and financial statement schedules.

Basis for Opinion

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 are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. 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.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed 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 its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, 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.

/s/ *DELOITTE & TOUCHE LLP*

Boise, Idaho
February 21, 2019

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, 2018, 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, 2018. 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, 2018, 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, 2018 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, 2018.

February 21, 2019

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the shareholder and Board of Directors of Idaho Power Company

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of Idaho Power Company and subsidiary (the "Company") as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements and financial statement schedule as of and for the year ended December 31, 2018 of the Company and our report dated February 21, 2019 expressed an unqualified opinion on those financial statements and financial statement schedule.

Basis for Opinion

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 are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. 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.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed 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 its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, 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.

/s/ *DELOITTE & TOUCHE LLP*

Boise, Idaho
February 21, 2019

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, 2018 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 2019 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 2019 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 2019 annual meeting of shareholders is hereby incorporated by reference. The table below includes information as of December 31, 2018, with respect to the IDACORP 2000 Long-Term Incentive and Compensation Plan (LTICP) pursuant to which equity securities of IDACORP may be issued.

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	139,353 (1)	$ — (2)	720,408 (3)
Equity compensation plans not approved by shareholders	—	$ —	—
Total	139,353	$ —	720,408

(1) Represents shares subject to outstanding time-based restricted stock units and performance-based restricted stock units (at target).

(2) Time-based restricted stock units and performance-based restricted stock units have no exercise price.

(3) 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. 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 as of December 31, 2018.

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 2019 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 2019 annual meeting of shareholders is hereby incorporated by reference.

Idaho Power: The table below presents the aggregate fees of Idaho Power's 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, 2018 and 2017:

	2018	2017
Audit fees	$ 1,437,100	$ 1,379,000
Audit-related fees[1]	29,550	39,400
Tax fees[2]	26,125	40,000
All other fees[3]	1,895	2,000
Total	$ 1,494,670	$ 1,460,400

(1) Includes accounting-related consultation services.

(2) Includes fees for consultation related to tax planning and accounting.

(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 2018 and 2017, 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) 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	33-56071-99	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					
	File number 1-3198, Form 8-K filed on 9/27/2016, as Exhibit 4.1, Forty-eighth, September 1, 2016					
4.3	Instruments relating to Idaho Power Company American Falls bond guarantee (see Exhibit 10.16)	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	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	
10.2	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	
10.3	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	
10.4	Agreement, dated October 25, 1984, between the State of Idaho and Idaho Power Company, relating to the agreement filed as Exhibit 10.3	S-3	33-65720*	10(h)(i)	7/7/1993	

Exhibit No.	Exhibit Description	Incorporated by Reference Form	File No.	Exhibit No.	Date	Included Herewith
10.5	Contract to Implement, dated October 25, 1984, between the State of Idaho and Idaho Power Company, relating to the agreement filed as Exhibit 10.3	S-3	33-65720*	10(h)(ii)	7/7/1993	
10.6	Settlement Agreement, dated March 25, 2009, between the State of Idaho and Idaho Power Company relating to the agreement filed as Exhibit 10.3	10-Q	1-14465*	10.58	5/7/2009	
10.7	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	
10.8	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	
10.9	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	
10.10	Letter Agreement, effective as of November 7, 2016, 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, extending term of Credit Agreement	10-K	1-14465, 1-3198	10.20	2/23/2017	
10.11	Letter Agreement, effective as of November 7, 2016, 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, extending term of Credit Agreement	10-K	1-14465, 1-3198	10.21	2/23/2017	
10.12	Letter Agreement, effective as of November 7, 2017, 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, extending the term of the Credit Agreement	10-K	1-14465, 1-3198	10.12	2/22/2018	

Exhibit No.	Exhibit Description	Incorporated by Reference Form	File No.	Exhibit No.	Date	Included Herewith
10.13	Letter Agreement, effective as of November 7, 2017, 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, extending the term of the Credit Agreement	10-K	1-14465, 1-3198	10.13	2/22/2018	
10.14	Loan Agreement, dated October 1, 2006, between Sweetwater County, Wyoming and Idaho Power Company	8-K	1-3198	10.1	10/10/2006	
10.15	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	
10.16	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	
10.17[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	
10.18[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	
10.19[1]	Idaho Power Company Security Plan for Senior Management Employees II, as amended and restated February 8, 2017	10-K	1-14465, 1-3198	10.31	2/23/2017	
10.20[1]	Amendment to the Idaho Power Company Security Plan for Senior Management Employees II, as amended May 17, 2017	10-Q	1-14465, 1-3198	10.1	8/3/2017	
10.21[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	
10.22[1]	IDACORP, Inc. Non-Employee Directors Stock Compensation Plan, as amended November 16, 2017	10-K	1-14465, 1-3198	10.22	2/22/2018	
10.23[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	
10.24[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	
10.25[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	
10.26[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	
10.27[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	
10.28[1]	IDACORP, Inc. and/or Idaho Power Company Executive Officers with Amended and Restated Change in Control Agreements chart, as of February 19, 2019					X
10.29[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan, as amended and restated February 9, 2017	10-K	1-14465, 1-3198	10.41	2/23/2017	
10.30[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Restricted Unit Award Agreement (Time Vesting)					X

		Incorporated by Reference				
Exhibit No.	Exhibit Description	Form	File No.	Exhibit No.	Date	Included Herewith
10.31[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Performance Unit Award Agreement (Performance with Total Shareholder Return Goal)					X
10.32[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Performance Unit Award Agreement (Performance with Cumulative Earnings Per Share Goal)					X
10.33[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Restricted Unit Award Agreement (Time Vesting) (For 2017 and 2018 Outstanding Awards)	10-K	1-14465, 1-3198	10.42	2/23/2017	
10.34[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Performance Unit Award Agreement (Performance with Total Shareholder Return Goal) (For 2017 and 2018 Outstanding Awards)	10-K	1-14465, 1-3198	10.43	2/23/2017	
10.35[1]	IDACORP, Inc. 2000 Long-Term Incentive and Compensation Plan - Form of Performance Unit Award Agreement (Performance with Cumulative Earnings Per Share Goal) (For 2017 and 2018 Outstanding Awards)	10-K	1-14465, 1-3198	10.44	2/23/2017	
10.36[1]	IDACORP, Inc. Executive Incentive Plan, as amended and restated November 14, 2018					X
10.37[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	
10.38[1]	IDACORP, Inc. and Idaho Power Company Compensation for Non-Employee Directors of the Board of Directors, effective January 1, 2019					X
10.39[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	
10.40[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	
10.41[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	
10.42[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	
10.43[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	
10.44[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	
10.45[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	
10.46[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	
10.47[1]	Idaho Power Company Restated Employee Savings Plan, as restated as of January 1, 2016	10-K	1-14465, 1-3198	10.59	2/18/2016	
10.48[1]	Amendment, dated effective December 1, 2016, to the Idaho Power Company Restated Employee Savings Plan, as restated as of January 1, 2016	10-K	1-14465, 1-3198	10.61	2/23/2017	
10.49[1]	Second Amendment to the Idaho Power Company Employee Savings Plan, as amended January 1, 2018	10-Q	1-14465, 1-3198	10.1	11/2/2017	
10.50[1]	Third Amendment to the Idaho Power Company Employee Savings Plan, as amended April 26, 2018	10-Q	1-14465, 1-3198	10.4	5/3/2018	
21.1	Subsidiaries of IDACORP, Inc.					X
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

Exhibit No.	Exhibit Description	Incorporated by Reference Form	File No.	Exhibit No.	Date	Included Herewith
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
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

* Exhibit originally filed with the U.S. Securities and Exchange Commission in paper format and as such, a hyperlink is not available.

(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,		
	2018	2017	2016
	(thousands of dollars)		
Income:			
Equity in income of subsidiaries	$ 226,567	$ 211,974	$ 198,061
Investment income	865	26	3
Total income	227,432	212,000	198,064
Expenses:			
Operating expenses	668	708	716
Interest expense	713	294	333
Other expenses	—	30	45
Total expenses	1,381	1,032	1,094
Income Before Income Taxes	226,051	210,968	196,970
Income Tax Benefit	(750)	(1,451)	(1,318)
Net Income Attributable to IDACORP, Inc.	226,801	212,419	198,288
Other comprehensive income (loss)	8,120	(5,990)	394
Comprehensive Income Attributable to IDACORP, Inc.	$ 234,921	$ 206,429	$ 198,682

The accompanying note is an integral part of these statements.

IDACORP, INC.
CONDENSED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2018	2017	2016
	(thousands of dollars)		
Operating Activities:			
Net cash provided by operating activities	$ 197,185	$ 113,849	$ 139,077
Investing Activities:			
Net cash provided by (used in) investing activities	—	—	—
Financing Activities:			
Dividends on common stock	(121,421)	(113,127)	(104,985)
Decrease in short-term borrowings	—	—	(20,000)
Change in intercompany notes payable	(2,867)	17,097	2,421
Other	(3,614)	(3,321)	(3,422)
Net cash used in financing activities	(127,902)	(99,351)	(125,986)
Net increase in cash and cash equivalents	69,283	14,498	13,091
Cash and cash equivalents at beginning of year	29,617	15,119	2,028
Cash and cash equivalents at end of year	$ 98,900	$ 29,617	$ 15,119

The accompanying note is an integral part of these statements.

IDACORP, INC.
CONDENSED BALANCE SHEETS

	December 31,	
	2018	**2017**
Assets	**(thousands of dollars)**	
Current Assets:		
Cash and cash equivalents	$ 98,900	$ 29,617
Receivables	2,046	52,359
Other	98	98
Total current assets	101,044	82,074
Investment in subsidiaries	2,294,464	2,189,017
Other Assets:		
Deferred income taxes	17,593	34,040
Other	277	374
Total other assets	17,870	34,414
Total assets	$ 2,413,378	$ 2,305,505
Liabilities and Shareholders' Equity		
Current Liabilities:		
Accounts payable	$ —	$ 17
Taxes accrued	8,354	17,423
Other	899	626
Total current liabilities	9,253	18,066
Other Liabilities:		
Intercompany notes payable	32,929	35,140
Other	836	914
Total other liabilities	33,765	36,054
IDACORP, Inc. Shareholders' Equity	2,370,360	2,251,385
Total Liabilities and Shareholders' Equity	$ 2,413,378	$ 2,305,505

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 U.S. 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 2018 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 $124 million, $116 million, and $108 million in 2018, 2017, and 2016, respectively.

IDACORP, INC.
SCHEDULE II - CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
Years Ended December 31, 2018, 2017, and 2016

Classification	Balance at Beginning of Year	Additions: Charged to Income	Additions: Charged (Credited) to Other Accounts	Deductions[1]	Balance at End of Year
	(thousands of dollars)				
2018:					
Reserves deducted from applicable assets:					
Reserve for uncollectible accounts	$ 2,193	$ 3,363	$ 392	$ 3,959	$ 1,989
Reserve for uncollectible notes	402	—	—	—	402
Other Reserves:					
Injuries and damages	1,469	855	—	447	1,877
2017:					
Reserves deducted from applicable assets:					
Reserve for uncollectible accounts	$ 1,132	$ 5,753	$ 324	$ 5,016	$ 2,193
Reserve for uncollectible notes	402	—	—	—	402
Other Reserves:					
Injuries and damages	1,792	687	—	1,010	1,469
2016:					
Reserves deducted from applicable assets:					
Reserve for uncollectible accounts	$ 1,355	$ 3,917	$ 263	$ 4,403	$ 1,132
Reserve for uncollectible notes	552	—	—	150	402
Other Reserves:					
Injuries and damages	1,874	848	—	930	1,792

(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 reserved.

IDAHO POWER COMPANY
SCHEDULE II - CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
Years Ended December 31, 2018, 2017, and 2016

Classification	Balance at Beginning of Year	Additions: Charged to Income	Additions: Charged (Credited) to Other Accounts	Deductions[1]	Balance at End of Year
	(thousands of dollars)				
2018:					
Reserves deducted from applicable assets:					
Reserve for uncollectible accounts	$ 2,193	$ 3,363	$ 392	$ 3,959	$ 1,989
Other Reserves:					
Injuries and damages	1,469	855	—	447	1,877
2017:					
Reserves deducted from applicable assets:					
Reserve for uncollectible accounts	$ 1,132	$ 5,753	$ 324	$ 5,016	$ 2,193
Other Reserves:					
Injuries and damages	1,792	687	—	1,010	1,469
2016:					
Reserves deducted from applicable assets:					
Reserve for uncollectible accounts	$ 1,355	$ 3,917	$ 263	$ 4,403	$ 1,132
Other Reserves:					
Injuries and damages	1,874	848	—	930	1,792

(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 reserved.

ITEM 16. FORM 10-K SUMMARY

None.

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 21, 2019		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 21, 2019
/s/ Darrel T. Anderson Darrel T. Anderson President and Chief Executive Officer and Director	(Principal Executive Officer)	February 21, 2019
/s/ Steven R. Keen Steven R. Keen Senior Vice President, Chief Financial Officer, and Treasurer	(Principal Financial Officer)	February 21, 2019
/s/ Kenneth W. Petersen Kenneth W. Petersen Vice President, Controller, and Chief Accounting Officer	(Principal Accounting Officer)	February 21, 2019
/s/ Thomas Carlile Thomas Carlile	Director	February 21, 2019
/s/ Richard J. Dahl Richard J. Dahl	Director	February 21, 2019
/s/ Annette G. Elg Annette G. Elg	Director	February 21, 2019
/s/ Ronald W. Jibson Ronald W. Jibson	Director	February 21, 2019
/s/ Judith A. Johansen Judith A. Johansen	Director	February 21, 2019
/s/ Dennis L. Johnson Dennis L. Johnson	Director	February 21, 2019
/s/ Christine King Christine King	Director	February 21, 2019
/s/ Richard J. Navarro Richard J. Navarro	Director	February 21, 2019

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 21, 2019
Date

Idaho Power Company

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 21, 2019
/s/ Darrel T. Anderson Darrel T. Anderson President and Chief Executive Officer and Director	(Principal Executive Officer)	February 21, 2019
/s/ Steven R. Keen Steven R. Keen Senior Vice President, Chief Financial Officer, and Treasurer	(Principal Financial Officer)	February 21, 2019
/s/ Kenneth W. Petersen Kenneth W. Petersen Vice President, Controller, and Chief Accounting Officer	(Principal Accounting Officer)	February 21, 2019
/s/ Thomas Carlile Thomas Carlile	Director	February 21, 2019
/s/ Richard J. Dahl Richard J. Dahl	Director	February 21, 2019
/s/ Annette G. Elg Annette G. Elg	Director	February 21, 2019
/s/ Ronald W. Jibson Ronald W. Jibson	Director	February 21, 2019
/s/ Judith A. Johansen Judith A. Johansen	Director	February 21, 2019
/s/ Dennis L. Johnson Dennis L. Johnson	Director	February 21, 2019
/s/ Christine King Christine King	Director	February 21, 2019
/s/ Richard J. Navarro Richard J. Navarro	Director	February 21, 2019

IDACORP INC. & IDAHO POWER ( ) total years of service

Darrel T. Anderson (23)
President and Chief Executive Officer

Brian R. Buckham (8)
Senior Vice President and General Counsel

Patrick A. Harrington (33)
Corporate Secretary

Steven R. Keen (36)
Senior Vice President, Chief Financial Officer and Treasurer

Jeffrey L. Malmen (11)
Senior Vice President of Public Affairs

Ken W. Petersen (20)
Vice President, Controller and Chief Accounting Officer

IDAHO POWER

Lisa A. Grow (31)
Senior Vice President and Chief Operating Officer

Jeffrey S. Glenn (3)
Vice President of Information Technology and Chief Information Officer

Tessia Park (21)
Vice President of Power Supply

N. Vern Porter (29)
Vice President of Transmission & Distribution Engineering and Chief Safety Officer

Adam J. Richins (7)
Vice President of Customer Operations and Business Development

Tim E. Tatum (23)
Vice President of Regulatory Affairs

IDACORP, Inc., Boise, Idaho-based and formed in 1998, is a holding company composed of Idaho Power, a regulated energy company; 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. Idaho Power began operations in 1916 and 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 560,000 residential, business and agricultural customers pay some of the nation's lowest prices for electricity. To learn more about IDACORP or Idaho Power, visit idacorpinc.com or idahopower.com.

Forward-Looking Statements: Please refer to IDACORP's and Idaho Power's Annual Report on Form 10-K for a description of the risks and uncertainties related to the forward-looking statements included in this Annual Report.

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
EQ 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

Contacts

Broker/Analyst Contact: Justin S. Forsberg
Director of Investor Relations
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Email: jforsberg@idacorpinc.com

Shareowner Contact: Colette Shepard
Phone: 1-800-635-5406, 208-388-2564, 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, ID 83702-5627
Phone: 208-388-2200
Website: idacorpinc.com

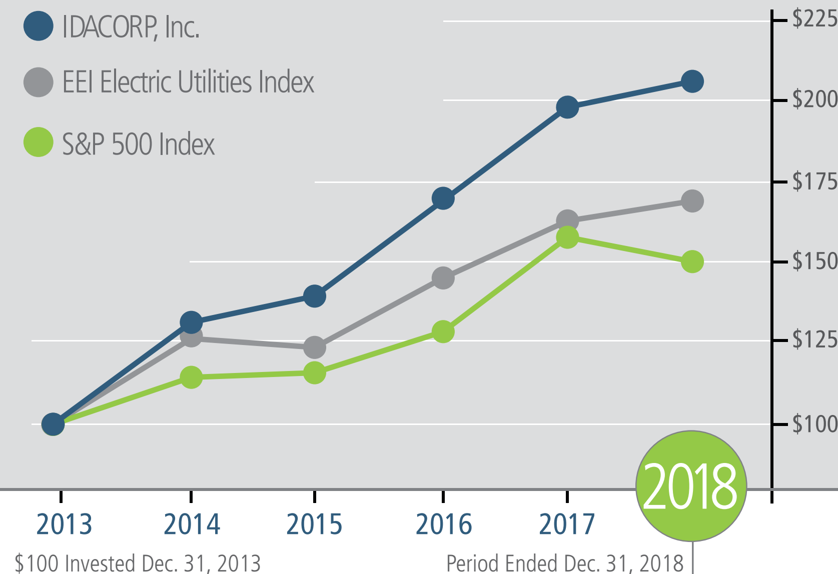
SEC Form 10-K

The IDACORP, Inc. and Idaho Power 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.

2019 Annual Meeting

The 2019 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 16, 2019. Formal notice of the meeting will be mailed to shareholders on or about Monday, April 1, 2019.

COMPARISON OF CUMULATIVE TOTAL RETURN



Annual REPORT

ADAPTABILITY

IDACORP

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Boise, ID 83707-0070
idacorpinc.com